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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re:	Petition for rate increase by Gulf Power Company	)))	DOCKET NO. 160186-EI

TESTIMONY OF KARL R. RÁBAGO
ON BEHALF OF
SOUTHERN ALLIANCE FOR CLEAN ENERGY AND THE LEAGUE OF WOMEN VOTERS OF FLORIDA

January 13, 2017

INTRODUCTION AND OVERVIEW

Q. Please state your name and business address.

A. My name is Karl R. Rábago. I am the Executive Director of the Pace Energy and Climate Center at the Elizabeth Haub School of Law ("Pace"). My business address is 78 North Broadway, White Plains, New York.

Q. What is Pace?

A. Pace is a project of the Elisabeth Haub School of Law at Pace University. As a non-partisan legal and policy think tank, Pace develops cost-effective solutions to complex energy and climate challenges and transforms the way society supplies and consumes energy. For more than twenty-five years, Pace has been providing legal, policy, and stakeholder engagement leadership in New York, the Northeast, and other jurisdictions. Located on the campus of the Elisabeth Haub School of Law, Pace engages and leverages a strong legal faculty and student body in its work, particularly through the internationally recognized Environmental Law Program and the Pace Land Use Law Center. Pace has many years of success in working with and supporting the New York State Energy Research and Development Authority ("NYSERDA"), the New York Public Service Commission ("NYPSC"), and the New York Department of Environmental Conservation. Pace's work also includes strategic engagement with state legislative and executive officials, as well as in key NYPSC proceedings. In these capacities, we have had the opportunity to form long-lasting partnerships within the community of non-governmental organizations that work in the field of energy.

Q. Please summarize your background and experience.

A. I have some twenty-five years' experience in electric utility regulation, the electricity business, technology development, and markets. I am an attorney with degrees from Texas A&M University and the University of Texas School of Law, and post-doctorate degrees in military and environmental law from the U.S. Army Judge Advocate General's School and Pace School of Law, respectively. Of note, my previous employment experience includes serving as a Commissioner with the Public Utility Commission of Texas, Deputy Assistant Secretary with the U.S. Department of Energy, Vice President with Austin Energy, and Director of Regulatory Affairs with AES Corporation. I am also principal of Rábago Energy LLC, a consulting practice operating in New York. A detailed resume is attached as Exhibit KRR-1.

Q. Have you previously testified before this or any other Commission?

A. I submitted testimony in Florida Public Service Commission ("Commission") dockets 130199-EI, 130200-EI, 130201-EI, 130202-EI, and 150196-EI. In the past four years, I have submitted testimony, comments, or presentations in proceedings in New Hampshire, Virginia, New York, Hawaii, Iowa, Indiana, Ohio, Rhode Island, Georgia, Massachusetts, Minnesota, Michigan, Missouri, Louisiana, North Carolina, Kentucky, Arizona, Wisconsin, Vermont, California, and the District of Columbia. A listing of my recent previous testimony is attached as Exhibit KRR-2.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review and respond to the proposal by Gulf Power Company ("Company") to increase and restructure residential rates.

Q. What information did you review in preparing this testimony?

A. I reviewed relevant prefiled testimony of Company witnesses, filed Company schedules and tables, and relevant Company responses to information requests. I also listened to depositions of Company witnesses Michael O'Sheasy, Jun Park, and Robert McGee.

Q. What are your recommendations to the Commission?

A. Based on my review of the evidence in this case, I make several recommendations to ensure that Gulf Power Company's residential rates are fair, just, and reasonable:

- The Commission should not approve the Company's proposal to increase fixed customer charges applicable to Residential customers via the untested and unstudied "Blank & Gegax" ("B&G") methodology, and should direct that any approved revenue requirement associated with those proposed rate changes be allocated solely to volumetric energy-demand charges.
- The Commission should not approve the Company's use of the minimum system approach for classifying customer costs and should direct the Company to employ an approach that assigns to the customer cost category those costs that vary solely or predominantly with changes in the customer count. That is, only customer-related costs should be included in the base charge.
- The Commission should not approve the Company's proposal to use a 1NCP allocator for any demand-related distribution costs, and should direct the Company to evaluate allocators that use many more hours in the non-coincident peak of customer classes or groups.

SUMMARY OF FINDINGS

Q. What are your findings regarding the Company's fixed customer charge proposals?

A. My findings are summarized as follows:

- The Company's proposal to expand the scope of fixed customer charges for residential rate classes to include demand charges is at odds with long-established principles of regulatory ratemaking practice.
- The Company has offered a deeply flawed, wholly unsubstantiated, and inadequate justification for its request to increase fixed customer charges for residential rate classes via the B&G methodology.
- The Company has selected cost classification and allocation methods, as well as the

B&G methodology, that result in unreasonably high customer costs for residential customers.

- The Company proposes a low-income customer subsidy program that fails to meaningfully mitigate the regressive impacts associated with its rate and rate structure proposals.
- The Company has failed to adequately consider the adverse impacts that its proposed fixed customer charges would have on low-income customers, economic efficiency, energy efficiency, conservation, and renewable energy.

THE COMPANY'S FIXED CUSTOMER CHARGE PROPOSAL FOR RESIDENTIAL CUSTOMERS

Q. What is the Company's proposal regarding fixed charge increases for residential customers?

A. The Company proposes to dramatically increase customer charges and reduce volumetric charges through two major sets of changes. First, through the cost allocation process, the Company proposes to increase the total revenue requirement assigned to the residential class by more than 20%, or more than $68 million. This change is proposed through use of a minimum system method for assigning costs to residential customers, as well as through increases in costs. Figure KRR-1, below, shows the difference between present residential rates by cost of service category with no minimum system methodology, and the costs allocated to residential customers under the proposed rates with the application of a minimum system methodology.

Figure KRR-1: Comparison of Residential Costs under Present and Proposed Approaches

		No Min System	With Min System		
		Present	Proposed		
Line No.	Description	Residential Rate Class ($000)	Residential Rate Class ($000)	Change in Costs to Residential Customers ($000)	Percent Change in Costs to Residential Customers
1	REVENUE REQUIREMENTS FROM				
2	SALE OF ELECTRICITY ($000)				
3	ENERGY (NON-FUEL PORTION)	22,228	25,069	**2,841**	**12.8%**
4	DEMAND	237,947	272,193	**34,246**	**14.4%**
5	PRODUCTION	124,107	143,932	**19,825**	**16.0%**
6	TRANSMISSION	39,518	54,426	**14,908**	**37.7%**
7	DISTRIBUTION	74,322	73,835	**-487**	**-0.7%**
8	CUSTOMER	67,564	98,646	**31,082**	**46.0%**
9	DISTRIBUTION	23,785	53,347	**29,562**	**124.3%**
10	CUSTOMER ACCOUNTS	28,074	28,993	**919**	**3.3%**
11	CUSTOMER ASSISTANCE	15,705	16,306	**601**	**3.8%**
12	CUSTOMER (LIGHTING FACIL)	0	-	**0**	
13	TOTAL REVENUE REQUIREMENT	327,739	395,908	**68,169**	**20.8%**
14	BILLING UNITS (ANNUAL)				
15	ENERGY (MWH)	5,336,892	5,336,892	**0**	**0.0%**
16	BILLING DEMAND (KW)				
17	SBS BILLING KW FOR RSRV CHG				
18	CUSTOMER	4,796,951	4,796,951	**0**	**0.0%**
19	UNIT COST				
20	ENERGY (¢/KWH)	0.4165	0.46973	**0.053**	**12.8%**
21	CUSTOMER ($/CUST/MO OR ¢/KWH)	14.08	20.56	**6.480**	**46.0%**
22	CUSTOMER(LIGHTING FACIL.)				
23	($/CUSTOMER/MO)				
24	DEMAND- PRODUCTION- $/CUST/MO	25.87	30.00	**4.13**	**16.0%**
25	DEMAND- TRANSMISSION- $/CUST/MO	8.24	11.35	**3.11**	**37.7%**
26	DEMAND- DISTRIBUTION -$/CUST/MO	15.49	15.39	**-0.10**	**-0.6%**
27	DEMAND- PRODUCTION - $/KW				
28	DEMAND- TRANSMISSION- $/KW				
29	DEMAND- DISTRIBUTION - $/KW				
30	DEMAND- PRODUCTION- ¢/KWH	2.32545	2.69693	**0.3715**	**16.0%**
31	DEMAND- TRANSMISSION - ¢/KWH	0.74047	1.01981	**0.2793**	**37.7%**
32	DEMAND- DISTRIBUTION -¢/KWH	1.39261	1.38348	**-0.0091**	**-0.7%**

Source: MFR Section E, Schedules E-6a, E-6b.

Q. What is the second way that the Company proposes to change residential rates?

A. The Company is proposing what it calls an “Advanced Pricing Package” to impose regressive increases in fixed customer charges through the application of an unproven and untested method that it found in a trade publication called the “Blank & Gegax” (“B&G”) method. The total impact on residential customers taking service under the default residential rate RS of the proposed changes in cost allocation and rate structure is depicted in Figure KRR-2.

Figure KRR-2: Impact of Company Proposals on Total Monthly RS Bill

	Total Monthly Bill						
	RS						
Billing Determinants	Current Rates			Proposed Rates			
Energy	Current Structure	Proposed Structure	Percent Change	Current Structure	Proposed Structure	Percent Change	Percent Change from Current Rates
0	$ 18.87	$ 41.09	118%	$ 20.39	$ 48.09	136%	155%
100	$ 30.24	$ 50.59	67%	$ 32.38	$ 57.76	78%	91%
300	$ 52.95	$ 69.56	31%	$ 56.35	$ 77.08	37%	46%
500	$ 75.68	$ 88.56	17%	$ 80.34	$ 96.43	20%	27%
750	$ 104.07	$ 112.28	8%	$ 110.30	$ 120.60	9%	16%
1000	$ 132.46	$ 136.00	3%	$ 140.27	$ 144.76	3%	9%
1112	$ 145.19	$ 146.63	1%	$ 153.59	$ 155.58	1%	7%
1250	$ 160.86	$ 159.73	-1%	$ 170.25	$ 168.94	-1%	5%
1500	$ 189.27	$ 183.47	-3%	$ 200.22	$ 193.10	-4%	2%
1750	$ 217.66	$ 207.19	-5%	$ 230.18	$ 217.27	-6%	0%
2000	$ 246.05	$ 230.91	-6%	$ 260.15	$ 241.43	-7%	-2%

Source: Exhibit RLM-1, Schedule 6.

Q. Why does the Company's proposed customer charge increase so dramatically?

A. The proposed increase is a function of a Company proposal to allocate more demand-related costs to residential customers and the customer component of costs, and then to propose collection of those charges through the customer charge instead of through volumetric charges, as is the normal practice among investor owned utilities throughout the United States.

Q. What does the data show about the Company's proposed revenue and rate changes?

A. The Company proposes a 155% increase in the residential customer charge under Rate RS, from $0.62/day/customer to $1.58/day/customer. The Company also proposes a 28% decrease in the energy component of volumetric (per kWh) charges. The Company proposes to increase revenues collected from the residential class by a total of $68,169,000, and to heavily skew the changes in revenue collection to low-use customers.

Q. How does the Company justify its proposal to increase the amount of revenue

allocated to customer charges so dramatically?

A. Company witnesses O'Sheasy and McGee provide the Company's rationale for these increases. In general, witness O'Sheasy advances the Company's proposals related to cost of service and cost allocation. Witness McGee advances the residential rate structure proposals and application of the B&G methodology for designing rates.

Q. How does the Company propose that costs be allocated in this rate case?

A. As shown in Figure KRR-1, witness O'Sheasy proposes, as a result of the cost of service study and the application of the minimum system method for allocating costs, to increase the revenue requirement assigned to residential customers by $68,169,000, or 20.8% over the present revenue requirement without the minimum system. This total increase results from a 12.8% increase in non-fuel energy costs assigned to residential customers ($2,841,000), a 14.4% increase in costs allocated to the demand component ($34,246,000) of residential rates, and a 46% ($31,082,000) increase in costs allocated to the customer component. Of that increase in the customer component of residential revenue requirement under the proposed rates, the vast majority ($29,562,000) results from more than doubling the demand-related costs allocated to the customer component.

Q. What are the consequences of the Company's decisions regarding cost classification for distribution system costs?

A. The minimum system method overstates customer-related costs because most distribution system costs, even those associated with the components of a minimum system, are not directly caused by the addition of new customers to the system. The Company chose an approach that allocates a larger portion of fixed distribution system costs to customer charges, with the result that the customer charge represents a large fraction of sunk fixed costs that a customer would have to pay regardless of the costs these customers cause. As a result, the minimum system approach also imposes unjust burdens on low-income and low-use customers. For these and other reasons, even Bonbright rejected the minimum system and zero-intercept methods for classifying customer costs.

Q, Is the inclusion of costs not directly caused by the addition of new customers to the system consistent with long-established principles of electric utility regulation and ratemaking?

A. No. For example, Bonbright, attached as Exhibit KRR-3, defines the fixed customer charge on pages 347-349 as follows:

> *These are those operating and capital costs found to vary with the number of customers regardless, or almost regardless, of power consumption. Included as a minimum are costs of metering and billing along with whatever other expenses the company must incur in taking on another consumer.*

In fact, Bonbright rejected the minimum system and zero-intercept methods for classifying customer costs that are at the foundation of the proposals advanced by Company witnesses O'Sheasy and McGee.

Q. Are established practices for setting the customer charge better and fairer?

A. Yes. Best practices assign to the customer cost category those costs that directly vary with the number of customers. Again, these costs would include a portion of the meter, service drop, meter reading, billing, and collection costs.

Q. How much cost does a new customer cause?

A. Costs directly related to new customers include a portion, but not all, of the cost of a meter, billing and metering services, and collection costs. These costs would likely sum to about $5-$10 per customer per month, depending on local costs, billing period used, and other factors. *See* Exhibit KRR-4 at page D-6. New customers certainly do not add all the costs that the Company would assign to the customer component under witness O'Sheasy's cost of service study and cost allocation proposals when those customers take service from the Company.

Q. Does a focus on costs caused by new customer connections properly address fixed costs already incurred to build the distribution system that the customer connects to?

A. Yes. The volumetric charge can fully recover those sunk fixed costs, preserve cost-causation features, and send more rational price signals to residential customers. As stated by noted utility economist, Severin Borenstein:

> *[T]he mere existence of systemwide fixed costs doesn't justify fixed charges. We should get marginal prices right, including the externalities associated with electricity production. We should use fixed charges to cover customer-specific fixed costs. Beyond that, we should think hard about balancing economic efficiency versus fairness when we use additional fixed charges to help address revenue shortfalls.*

Borenstein's article is attached as Exhibit KRR-5.

Q. Is the Company's approach the only approach that it could have used to design residential charges?

A. No. Other methods are appropriate, and, in light of the unjust discrimination and economic inefficiency that results from the Company proposal and the existence of other reasonable approaches, the Company proposal is unreasonable. I will discuss these impacts and alternatives in more detail.

Q. What is the B&G method and why does the Company propose to use it in restructuring residential rates?

A. Witness McGee asserts that the B&G method is a way of integrating demand costs into rates without having to offer a three-part rate (with a separate demand charge) as the default rate for residential service. It may be that, but it is also an untested, unstudied, and clearly regressive approach to rate design that should not be used, for the first time anywhere, as the default rate design for an entire residential customer class.

The B&G method is simply an arithmetic exercise to raise all residential customer charges and flatten the slope of the curve delineating how bills increase with usage. That is, the method forces a single straight-line fit onto a sample of residential data to increase customer charges by nearly $30 per month while also reducing energy charges for high users. Like witness McGee, the B&G method offers no detailed analysis of the relationship between customer demand and energy consumption, does no analysis of the cost to serve customers, and has no authoritative support for its propositions. Rather, it is proposed solely as a method for incorporating demand-related costs into customer charges without having to offer a three-part rate.

Witness McGee asserts that the B&G method cures an inequity in rates that he did not demonstrate to exist, that it reduces monthly bill volatility by fixing a much larger portion of each month's bill and reducing volumetric charges, and that for customers who do not like the increased monthly fixed charges, the Company offers a three-part rate that witness McGee admits is generally disfavored by customers and rarely used in the United States.

Q. Why does the Company propose rate restructuring based on the B&G method?

A. Company witness McGee makes a number of arguments in support of the Company's proposal to dramatically increase the customer charges even beyond what the cost of service and cost allocation approaches would. Witness McGee asserts that because low-use customers pay less in demand-related costs through volumetric rates than the average residential customers, they are not paying their fair share of demand-related costs.

Similarly, witness McGee asserts the Company's belief that because high users pay more in demand related costs than the average residential customer, they are being unfairly required to bear a cost burden they did not cause.

Q. Does witness McGee offer any testimony or point to any analysis to substantiate his claim that high users are being treated inequitably when volumetric rates cause them to pay more than the average customer in demand-related costs?

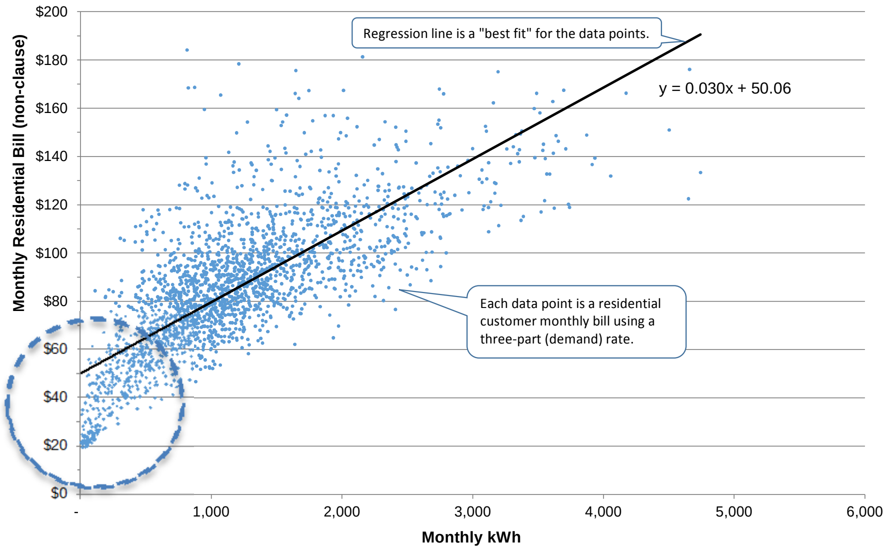
A. No. Witness McGee bases his assertions about inequities on an unsubstantiated premise that rate design should mimic utility cost structure in order to advance economic efficiency and equity among customers. He cites no cost of service analysis to suggest that high users create lower demand costs than low users.

Q. Is it likely that witness McGee has discovered a condition among Company customers that demonstrates that high users are low demand-cost causers, and that low users are, in turn, high demand-cost creators?

A. No. It is not surprising that witness McGee offers no analytical support for the argument that forms the foundation for the Company's rate restructuring proposal. In my 25-plus years of work in the electricity industry, including review of and on-the-record decisions in hundreds of rate cases, I have never seen a utility that has a cost of service structure that differs from the general trend that high users are also high demand cost drivers. Indeed, this observable general reality is supported by common sense. High user customers tend to be high income customers, living in larger homes. These customers have and operate many more appliances and systems that add to their demand profile.

Indeed, even the Company's data bears out this relationship. A visual review of Figure 1 in witness McGee's Exhibit RLM-1, Schedule 5 shows that even when a hypothetical three-part demand rate is applied to a sampling of residential customers, there is a heavy concentration of customers with low bills, low use, and low demand.

Figure 1
B&G Methodology
Regression Through Three-Part Rate Bills



Source: Company Exhibit RLM-1, Schedule 5, Page 3 of 4.

Q. Do you agree with witness McGee's assertion that economic efficiency and equity are advanced when rate design mimics cost structure?

A. No. In my 25-plus years' experience in the electricity industry, I have never found any article, text, treatise, or other reputable source to support the notion that rate design must mimic cost structure in order to achieve or advance economic efficiency. Witness McGee offered none.

Q. What could the Company have learned by reviewing similar proposals from other utilities in the United States?

A. A review of similar requests by other utilities and action taken in regulatory proceedings reveals that the Company's request is wildly outside of the range of experience in the United States. Figure KRR-3 below provides information about customer fixed charge requests over the past several years. It shows that the Company's proposed 155%

increase in fixed customer charges for residential customers is an extreme outlier compared to what has been requested and approved when compared to more than fifty cases from across the United States. The average increase in those other cases was only 21%, less than one sixth of the Company proposal. Almost half of the cases resulted in no approved increase to the fixed customer charges at all. It is also worth noting that nearby and similarly situated utilities Georgia Power and Duke Energy Florida use rates that rely on volumetric charges to recover demand and energy costs. In fact, Georgia Power has a residential fixed-charge of $10 per month, Duke Energy Florida has a fixed charge of $8.76 per month, Florida Power & Light has a fixed charge of $7.87 per month, the Orlando Utilities Commission has a fixed charge of $8 per month, the City of Tallahassee has a fixed charge of $7.41 per month, and JEA has a fixed charge of $5.50 per month. *See* Exhibit KRR-6. Gulf Power Company already has a high fixed charge that is out of step with its neighbors, and is proposing a 155% increase on top of that.

Figure KRR-3: Results Summary of 2014-2016 Fixed Charge Increase Proposals

Results Summary of 2014-2016 Fixed Charge Increase Proposals

				Monthly Fixed Residential Charges			Percent Change			
State	**Utility**	**Holding Company**	**Electric/**	**Existing**	**Proposed**	**Approved**	**Existing to**	**Existing to**	**Notes**	**Effective Date**
Electric										
AR	Entergy Arkansas	Entergy Corporation	Electric	$6.95	$9.00	$8.43	29%	21%		2/2016
AZ	UniSource Energy Services	Fortis	Electric	$10.00	$20.00	$15.00	100%	50%	Also rejected mandatory demand	8/2016
CA	Pacific Gas & Electric Company	PG&E Corp	Electric	$0.00	$10.00	$0.00	-	0%	$10 minimum bill adopted instead	7/2015
CA	San Diego Gas & Electric	Sempra Energy	Electric	$0.00	$10.00	$0.00	-	0%	$10 minimum bill adopted instead	7/2015
CA	Southern California Edison	Edison International	Electric	$0.95	$10.00	$0.95	953%	0%	$10 minimum bill adopted instead	7/2015
CT	Connecticut Light & Power	Eversource Energy	Electric	$16.00	$25.50	$19.25	59%	20%		12/2014
ID	Avista Utilities	Avista Utilities	Electric	$5.25	$8.50	$5.25	62%	0%	Settlement; decoupling pilot	12/2015
IN	Indianapolis Power & Light	AES	Electric	$6.70	$11.25	$11.25	68%	68%		3/2016
IN	Northern Indiana Public Service	NiSource Inc.	Electric	$11.00	$20.00	$14.00	82%	27%	Settlement	7/2016
KS	KCP&L	Great Plains Energy	Electric	$10.71	$19.00	$14.00	77%	31%	Settlement	9/2015
KS	Westar	Westar	Electric	$12.00	$27.00	$14.50	125%	21%	Settlement	9/2015
KY	Kentucky Utilities Company	PPL Corp	Electric	$10.75	$18.00	$10.75	67%	0%	Settlement	6/2015
KY	Louisville Gas-Electric	PPL Corp	Electric	$10.75	$18.00	$10.75	67%	0%	Settlement	6/2015
KY	Kentucky Power	AEP	Electric	$8.00	$16.00	$11.00	100%	38%		6/2015
MD	Baltimore Gas +Electric	Exelon	Electric	$7.50	$10.50	$7.50	40%	0%	Settlement	12/2014
MD	Baltimore Gas +Electric	Exelon	Electric	$7.50	$12.00	$7.90	60%	5%	Noted gradualism	6/2016
ME	Central Maine Power Company	Iberdrola	Electric	$5.71	$20.00	$10.00	250%	75%	Decoupling implemented as well	8/2014
MI	Consumers Energy	CMS Energy Corporation	Electric	$7.00	$7.50	$7.00	7%	0%		11/2015
MI	DTE Electric Company	DTE Energy	Electric	$6.00	$10.00	$6.00	67%	0%		12/11/15
MI	Indiana Michigan Power	AEP	Electric	$7.25	$9.10	$7.25	26%	0%	Settlement	8/2015
MI	Wisconsin Public Service	WEC Energy Group	Electric	$9.00	$12.00	$12.00	33%	33%	Settlement	4/2015
MN	Xcel Energy	Xcel Energy	Electric	$8.00	$9.25	$8.00	16%	0%	Denied in favor of decoupling	5/2015
MO	Ameren	Ameren	Electric	$8.00	$8.77	$8.00	10%	0%	Emphasized customer control	4/2015
MO	KCP&L	Great Plains Energy	Electric	$9.00	$25.00	$11.88	178%	32%		9/2015
MO	Empire District Electric	Empire District Electric	Electric	$12.52	$18.75	$12.52	50%	0%	Settlement	6/2015
MT	Montana-Dakota Utilities	MDU Resources Group	Electric	$5.40	$7.50	$5.40	39%	0%	Settlement	3/2016
NM	El Paso Electric	El Paso Electric	Electric	$7.00	$10.00	$7.00	43%	0%	Rejected recommended decision,	6/2016
NV	Nevada Power	Nevada Energy/Berkshire I	Electric	$10.00	$15.25	$12.75	53%	28%		10/2014
NY	Central Hudson Gas & Electric	Fortis	Electric	$24.00	$30.00	$24.00	25%	0%		6/2015
NY	Consolidated Edison	Consolidated Edison	Electric	$15.76	$18.00	$15.76	14%	0%	Settlement	6/2015
NY	New York State Electric and Gas	Iberdrola	Electric	$15.11	$18.89	$15.11	25%	0%	Settlement	6/2016
NY	Rochester Gas & Electric	Iberdrola	Electric	$21.38	$26.73	$21.38	25%	0%	Settlement	6/2016
NY	Orange & Rockland	Consolidated Edison	Electric	$20.00	$25.00	$20.00	25%	0%	Settlement	10/2015
OK	Oklahoma Gas & Electric	OG&E Energy	Electric	$13.00	$26.54	$13.00	104%	0%	Settlement pending	
OK	Public Service Co. of Oklahoma	AEP	Electric	$16.16	$20.00	$20.00	24%	24%		4/2015
OR	Portland General Electric	Portland General Electric	Electric	$10.00	$11.00	$10.50	10%	5%	Settlement	11/2015
PA	Pennsylvania Power	FirstEnergy	Electric	$8.89	$12.71	$10.85	43%	22%	Settlement	4/2015
PA	West Penn Power	FirstEnergy	Electric	$5.00	$7.35	$5.81	47%	16%	Settlement	4/2015
PA	Metropolitan Edison	FirstEnergy	Electric	$8.11	$13.29	$10.25	64%	26%	Settlement	4/2015
PA	Pennsylvania Electric	FirstEnergy	Electric	$7.98	$11.92	$9.99	49%	25%	Settlement	4/2015
PA	PECO	Exelon	Electric	$7.09	$12.00	$8.45	69%	19%	Settlement; decoupling collaborative	12/2015
PA	PPL	PPL Corp	Electric	$14.09	$20.00	$14.09	42%	0%	Settlement; decoupling collaborative	11/2015
SD	NorthWestern Energy	Northwestern Company	Electric	$5.00	$9.00	$6.00	80%	20%	Settlement	11/2015
TX	El Paso Electric		Electric	$5.00	$10.00	$6.90	100%	38%	Settlement pending	
TX	Southwestern Public Service Company	Xcel Energy	Electric	$7.50	$9.50	$9.50	27%	27%		12/2015
UT	Rocky Mountain Power	PacifiCorp/Berkshire Hath	Electric	$5.00	$8.00	$6.00	60%	20%	Settlement	8/2014
VA	Appalachian Power Co	AEP	Electric	$8.35	$16.00	$8.35	92%	0%		11/2014
WA	Avista Utilities	Avista	Electric	$8.50	$14.00	$8.50	65%	0%	Settlement	1/2016
WA	PacifiCorp	PacifiCorp/Berkshire Hath	Electric	$7.75	$14.00	$7.75	81%	0%	Stated preference for decoupling	3/2015
WV	Appalachian Power/Wheeling Power	AEP	Electric	$5.00	$10.00	$8.00	100%	60%		5/2015
WI	Madison Gas and Electric	MGE Energy	Electric	$10.29	$68.00	$19.00	113%	87%		12/2014
WI	Xcel Energy	Xcel Energy	Electric	$8.00	$18.00	$14.00	113%	87%		12/2015
WI	We Energies	WEC Energy Group	Electric	$9.13	$16.00	$16.00	75%	75%		11/2014
WI	Wisconsin Public Service	WEC Energy Group	Electric	$10.40	$25.00	$19.00	140%	83%		11/2014
WI	Wisconsin Public Service	WEC Energy Group	Electric	$19.00	$25.00	$21.00	140%	83%	PSC to study on customer impacts	11/2015
				$9.35	**$16.25**	**$11.05**	**83%**	**21%**		

Source: Data compiled from various sources and cases.

Q. Does the Company approach align costs with cost causers based on a cost-of-service study?

A. No. The Company's rate proposals violate cost causation alignment principles in several ways, as I have already discussed. In fact, the proposed B&G method assigns equal and average shares of sunk fixed costs to all residential customers without any regard for whether those costs were caused by high users of the distribution system. The high fixed charges also immunize high users from the consequences of future high use of electricity, obviating the price signal benefits that attend to the use of volumetric charges to recover demand-related costs.

Q. Have other Commissions addressed the cost-causation argument offered by the Company in regard to proposed fixed charge increases?

A. Yes. Notably, the Illinois Commerce Commission recently addressed a fixed charge increase proposal in a natural gas case proposing a 43% increase. That order is attached as Exhibit KRR-7. That Commission was addressing another method for increasing fixed customer charges, the "Straight Fixed Variable" rates design, which has similar results and impacts as the proposed B&G method. In the final order in that case, the Illinois Commission stated:

> *The Companies' proposed SFV rate design diverges from cost-causation, substituting its "fixed" cost designation for cost causation as the determinative allocator. … By failing to send proper price signals, the Companies' proposed rate design denies consumers who conserve the benefit of their actions, and punishes customers who are frugal. The proposed SFV charges are indifferent to efficiencies in usage and demand. In contrast, the Commission has recognized that lower monthly customer charges and higher volumetric charges can advance energy use conservation and efficiency policy objectives by providing a greater*

> *price signal. … The Commission finds that Staff's and Intervenor's arguments in favor of assigning demand-based costs to volumetric charges are consistent with energy efficiency and the avoidance of cross subsidies.*

Exhibit KRR-7 at pages 167 through 170.

Q. Does the B&G method treat similarly situated customers the same and reduce unnecessary subsidies?

A. The Company provides no evidence to support such a finding. As I have explained, the Company proposal actually requires low-use customers to subsidize the high use customers who drive distribution costs and will require them to continue subsidizing them as those high users drive new distribution system costs.

Q. Is the rate design resulting from the application of the B&G method simple, easy to understand, and predictable?

A. Yes, as compared to the three-part rate that witness McGee offers as a straw man proposal. But the B&G approach is not unique in this regard, and the Company has not demonstrated that its proposed combination of fixed customer charges and volumetric rates is optimal, or is any more simple, easy to understand, or predictable than the current rate design with customer-driven customer charges and volumetric rates for energy and demand. Moreover, by locking demand-related costs into a non-bypassable customer charge that cannot be avoided through energy conservation or demand reduction, the Company is ignoring the price signal function of rates and will frustrate customers who try to do something—anything—to substantially reduce their bills. It is not good rate making design to make it practically impossible for low- and high-use customers to avoid the bill impacts of high fixed customer charges.

Q. Please explain.

A. Under the Company proposal, a residential customer would pay an extra $29.22 each month in the increased fixed customer charge. That customer would have to reduce their monthly use of electricity by 302 kWh *per month* in order to offset that increase, based on the proposed volumetric energy charge of $0.09667 per kWh (with clauses). In this way, it is highly predictable that most customers would not be able to undertake enough energy efficiency or conservation to offset the increased customer charge. This level of reduction would represent a greater than 25% decrease in the monthly consumption of the average residential customer served by the Company. The ability to effectively manage electric bills through reasonable efforts to conserve or become more efficient is likely preferable over bill stability to all but the most well-to-do and highest use customers.

Q. Does the Company proposal reduce weather risk by keeping bills level through high-use months?

A. Simple arithmetic suggests that differences in monthly bills are reduced when more of the bill is fixed. However, this reasoning is a somewhat cynical justification for extracting monopoly rents when the Company performed no analysis to demonstrate whether cost-effective energy efficiency and conservation could similarly and more affordably reduce month-to-month bill variability and reduce bills, and when the Company's own analysis shows that the price of this reduced monthly bill variability is an average bill increase of at least 10% for customers using about 1,000 kWh or less each month. *See* Figure KRR-2.

Q. Doesn't Company witness McGee testify that there is high customer satisfaction in flat monthly billing rate designs?

A. Yes. However, the proposal is not flat monthly billing. Moreover, the Company is not offering its proposed rate structure as an option for customers willing to pay higher fixed monthly charges in return for a reduction in volumetric charges. That proposition should be tested, if at all, as a voluntary offering before it is imposed as the default rate design for all residential customers.

Q. Does the Company's proposed approach result in rates that provide economic efficiency by exposing customers to the Company's cost structure?

A. Again, there is no evidence in economic literature, regulation, or rate making that economic efficiency is enhanced by crafting rate designs to match utility cost structures. The Company offers no evidence to support such a finding. I discuss the fallacy of economic efficiency through mirroring of cost structures in rate design in greater detail later in this testimony.

Q. Does the Company's approach gradually change the structure of rates and bills?

A. No. The Company proposes a 155% increase in the fixed customer charge for residential customers. The Company proposes a monthly bill increase of more than 20% for any customer using fewer than 500 kWh per month. These are not gradual changes.

Q. In summary, is the Company's proposal to restructure its residential rate design with increased customer fixed charges sound economics, regulation, and policy?

A. No. Peter Kind, who authored the "Disruptive Challenges" paper published by the Edison Electric Institute in 2013 that argued for fixed customer charges in the electric utility sector, attached as Exhibit KRR-8, recognized in a paper published in November of 2015 at page 12, attached as Exhibit KRR-9, that "many utilities have been seeking to increase fixed charges, while customers and policymakers are vehemently opposed to such action. An evolved approach would focus on common ground with win4 (i.e. beneficial to customers, policy, competitive providers and utilities) perspective." As Kind explained on page 30:

> *Adopting meaningful monthly fixed or demand charges system-wide will reduce financial risk for utility revenue collections for the immediate future, but this approach has several flaws that need to be considered when assessing alternatives through a win4 lens, by which all principal stakeholders benefit.*

Fixed charges:

- *do not promote efficiency of energy resource demand and capital investment;*
- *reduce customer control over energy costs;*
- *have a negative impact on low- or fixed-income customers; and*
- *impact all customers when select customers adopt [distributed energy resources] and potentially exit the system altogether, if high fixed charges are approved and the utility's cost of service increases.*

The Company's proposed residential rate approach and fixed customer charge proposal is bad for customers, policy, competitive providers, and even itself. As a recent report published by Consumers Union details, attached as Exhibit KRR-10, fixed charge proposals like the one put forth by the Company in this case harm customers in several ways, violate fundamental principles of rate design, are unsupported by sound argument, and are inconsistent with regulatory trends around the country.

THE COMPANY'S VOLUMETRIC ENERGY CHARGE PROPOSAL

Q. What other cost allocation proposals does the Company advance?

A. Notably, the Company also proposes a 1NCP allocator for demand-related distribution costs at Level 4 (Primary Distribution) and Level 5 (secondary distribution), (*see* Witness O'Sheasy Direct Testimony at page 14, lines 1-5), meaning that it proposes to assign these costs to classes based upon each customer class's single hourly maximum level of consumption over the course of a year, whenever it occurs. The Company approach sums each class's 1NCP level of consumption, calculates the class share of the total, and uses the resulting percentages to assign distribution system demand-related costs.

Q. What impact does this proposed approach in cost allocation have on proposed

rates?

A. The Company proposes to recover some demand-related costs in the volumetric energy charge for residential and other customers who do not pay a demand charge. All other distribution costs are proposed for collection through fixed customer charges. The use of the 1NCP allocator as proposed by the Company ignores the physical and engineering reality that customers with different coincident peaks can share system capacity, and therefore this approach will significantly overstate demand-related distribution costs, and can double-charge for distribution system costs unless every class experiences its coincident peak at exactly the same time.

Q. Please explain.

A. Distribution systems are built to meet maximum coincident peak, with a margin of safety. Different classes experience their peak demand at times different than the system peak; that is, they are non-coincident. Distribution systems are not built to serve the sum of all coincident peaks as this would be wasteful and unnecessary. The sum of non-coincident peaks is mathematically certain to be greater than the coincident peak demand under any realistic scenario. Therefore, rates should not be designed based on the false assumption that class costs are reflected in the simple sum of the non-coincident peaks of each customer class.

Q. Why does this matter in rate design?

A. Most importantly, the use of the 1NCP allocator for demand-related distribution costs improperly inflates the fixed charge now bearing demand-related costs. This violates the principle that rates should be based on cost causation.

Q. The Company proposes a decrease in the energy charge. How does that square with your testimony about the impacts of the use of the 1NCP allocator for demand-related distribution system costs?

A. The reduction in energy charges proposed by the Company is essentially a fall-out of the classification decision relating to customer- and demand-related costs. Accounting for the non-coincident peaks of different customer groups and classes is appropriate; a more appropriate method, however, would account for every hour that the system is used—an "8760NCP." Of course, statistical analysis would likely show that a smaller subset of hours would capture significant demand-related costs, but the use of the 1NCP allocator is too extreme a reduction in the number of examined hours. Use of a more broadly-based allocator would likely yield volumetric rates that are lower than those proposed by the Company, and account for the fact that customer groups/classes with disparate non-coincident peaks actually share system capacity. As I will explain, most of the revenues proposed for the customer charge could be collected through the volumetric charge without creating the adverse impacts associated with the Company's proposal.

TOTAL IMPACTS ON RESIDENTIAL CUSTOMERS

Q. What is the net effect of the Company's residential rate proposals on customer bills?

A. The Company proposals impose dramatically greater impacts on low-use customers than on high-use customers. *See* Figure KRR-2. Under the Company proposals, customers who use an average of 300 kWh per month or less would see at least a 46% increase in their monthly electric bills. Customers using 750 kWh per month or less would see at least a 16% increase in monthly bills. Outrageously, customers using 2,000 kWh or more per month would actually see bill decreases due to the reduced volumetric charge, even after the proposed increase in fixed customer charges. High-use residential customers, such as those who use 2,000 kWh per month or more, directly drive residential distribution system costs, requiring larger conductors, transformers, and other service equipment in the portion of the system that serves them. The result of the Company's proposed rate changes flies in the face of the principle of allocating costs to cost causers, and points out a major flaw in the Company's proposal to move residential rates to the proposed rate design.

Q. Taken together, are the Company's proposals regarding residential rates reasonable?

A. No.

IMPACTS ON LOW-USE AND LOW-INCOME CUSTOMERS

Q. Do increases in fixed charges pose potential problems for low-income, low-usage customers?

A. Yes. Increasing fixed charges can have disproportionate impacts on low usage customers (who are often low-income customers), customers on fixed incomes (who are frequently seniors), students, and customers who have aggressively pursued green building and energy efficiency. This is an area where the Company needs to demonstrate definitively that low-income customers will not be unfairly affected, but the Company fails to address the issue adequately in any of its testimony. Demonstrating that *some* low-income customers use more energy than the residential class average is not proof that low-income customers as a group use more than average.

Q. What do we know about the number of low-use customers in the Company service territory and the impacts of the proposed rates structures?

A. According to data supplied by the Company in response to Staff request for production of documents number 30, and attached as Exhibit KRR-11, more than 245,000 out of nearly 400,000 residential customers use fewer than 1,100 kWh per month, and will see a 9% or greater increase in monthly bills. Nearly 60,000 residential customers use fewer than 400 kWh per month, and will see at least a 27% increase in monthly bills.

Q. Are these problems associated with the Company's decision to pursue its rate restructuring proposals?

A. Yes. The Company's approach to its cost of service study and restructuring of rates with the B&G method are drivers for the unfairly discriminatory impacts of the Company's proposal. In addition, the proposed approach is bad policy for ensuring fairly priced universal access to electricity service. As Jim Lazar of the Regulatory Assistance Project, a noted author and utility rate expert, summarized:

> *[High fixed cost] rate design strikes directly at universal service, because it makes electricity service, even for the most basic and essential uses, unaffordable to low-income households. It does this (even if they are densely located in urban areas where distribution costs are very low), by averaging their cost of service with suburban and rural areas where per customer distribution costs are very different. In effect, under [high fixed cost] pricing, low-income households are made to subsidize higher-income, higher-usage households.*

Exhibit KRR-4 at page D-5.

Q. How does a change to higher fixed charges and lower volumetric charges impact low- and moderate-income customers and other low-use customers?

A. Allocation of costs to fixed, non-bypassable charges imposes a significant burden on low energy users who are low- and moderate-income customers, or customers on fixed incomes, many of whom are elderly. The higher fixed charge is economically regressive. As I previously described, the proposal increases bills for low-use customers much more than for high-use customers; in fact, the Company proposal reduces bills for the very highest users in the residential class. This "reverse Robin Hood" proposal subsidizes the well-to-do at the expense of the poor, people (often seniors) on fixed income, students, and other low users such as conservationists.

Q. What is the Company position on the impact of increased fixed customer charges on low-income customers?

A. The Company proposes a direct subsidy to about 35,000 customers who are qualified under the SNAP program to offset the impact of the increased fixed customer charge. (*See* witness McGee direct testimony at pages 16-19). The SNAP program is an income-tested program that provides nutritional assistance (food stamp) support to qualified citizens. Witness McGee asserts that a subsidy targeted only at low-income customers who have financial problems is efficient, and that the Company rate design eliminates a subsidy that has been flowing to low-income, low-use customers who do not qualify or apply for financial assistance. Witness McGee asserts that low-income, low-use customers who do not qualify for or apply for financial assistance should be required to pay more, much more, in monthly customer charges.

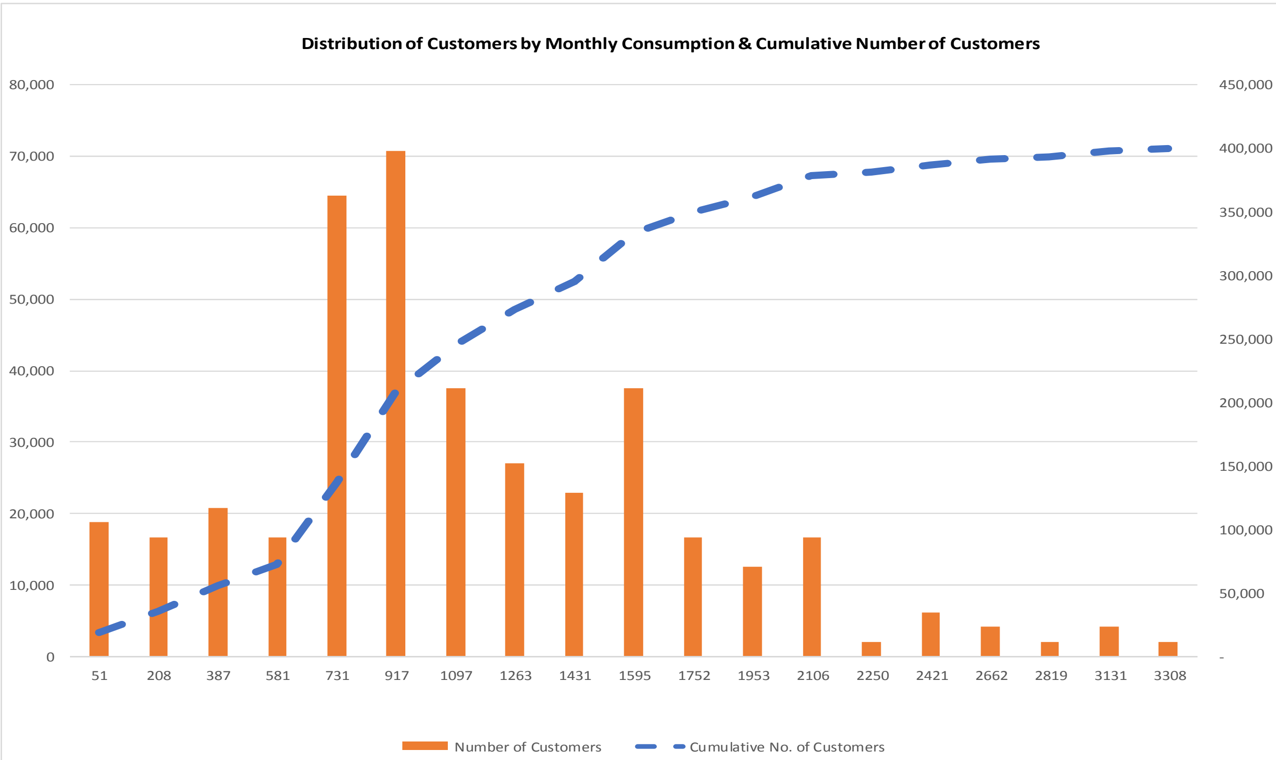
Q. What does SNAP program participation tell us about income and energy use for SNAP customers?

A. The Company offers no information to support any correlation between SNAP customers and low-income electricity customers. The Company has little or no data about customer income levels and cannot identify income levels by consumption level. SNAP customers may be customers in financial distress. They may or may not be high or low energy users.

Q. Should the Commission assume that qualification is indicative of low-income customer data?

A. No. The Company has no information to support any conclusion that SNAP customers encompass all or even a majority of the Company's low-income customers. As demonstrated in Figure KRR-4, what we do know is that about 50% of all residential customers—about 200,000 customers—in the Company service territory use about 900 kWh or less each month. These are the customers who will be most greatly burdened by the Company's proposals to restructure residential rates.

Figure KRR-4: Distribution of Residential Customer Accounts by Consumption Level



Source: Company Response to Staff POD Request 030, attached as Exhibit KRR-11.

Q. Is there any evidence available about whether low-income customers served by the Company have lower or higher use than residential customers as a whole?

A. Yes. SNAP customer data is unlikely to be representative of low-income customers as a whole. The SNAP program, like other assistance programs is targeted toward consumers in some financial distress. Many low-income customers who need assistance are homeowners, and assistance program participation tends to under-represent low-income customers who are renters and others who do not seek support from assistance programs.

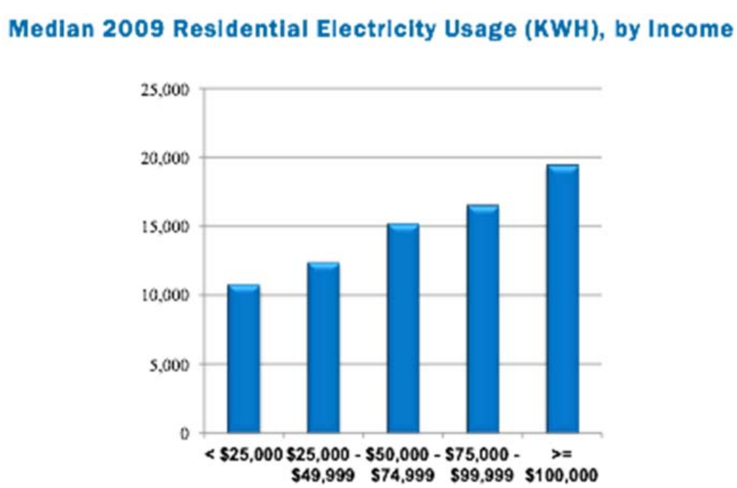
To better understand average low-income usage, it is critical to look at samples that include both program participants and non-participants. The Company has offered no such data. The only national data set that reflects such sampling is the EIA's Residential Energy Consumption Survey ("RECS"). The RECS includes detailed usage data, as well as information regarding household income, age, race, and numerous other characteristics. All of this is broken down into 27 geographic areas referred to as "reportable domains."

The National Consumer Law Center ("NCLC") has extracted this data for Florida customers and found that there is a clear and positive relationship between usage and income, just as exists in the rest of the United States. That is, the greater the income, the greater the average usage. In addition, the NCLC has found that customers 65 years of age or older also use markedly less electricity than younger customers.

Q. What does the NCLC report using the most recent U.S. Energy Information Administration's ("U.S. EIA") data demonstrate?

A. The most recently available data from the U.S. EIA and reported by NCLC reveals that the Company's fixed cost proposal would disproportionately burden low-income and elderly customers.

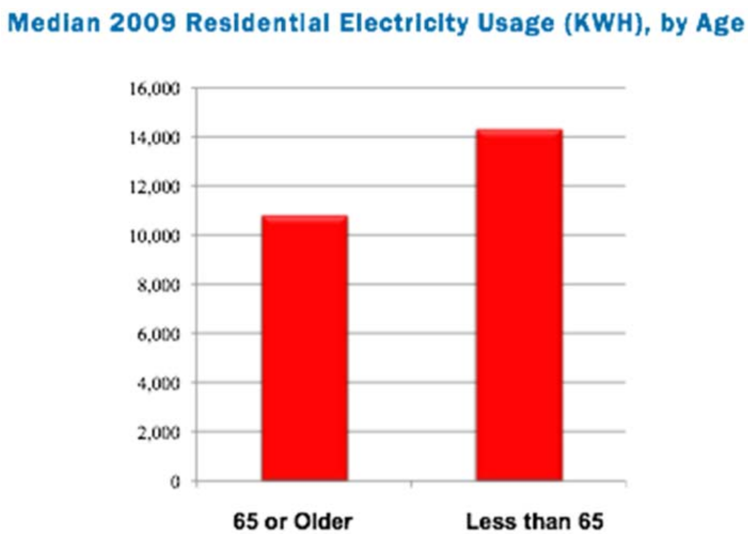
Figure KRR-5: Median 2009 Residential Electricity Usage (kWh) by Income, Florida



Source: NCLC, "Utility Rate Design: How Mandatory Monthly Customer Fees Cause

Disproportionate Harm," (2009 US EIA data), attached as Exhibit KRR-12.

Figure KRR-6: Median 2009 Residential Electricity Usage (kWh), by Age, Florida



Source: NCLC, "Utility Rate Design: How Mandatory Monthly Customer Fees Cause Disproportionate Harm" (2009 US EIA data), attached as Exhibit KRR-12.

Q. Is the Company's Low-Income subsidy proposal reasonable?

A. No. The Company has not demonstrated that low-use customers are high demand-cost causers. Given that the very opposite is likely true, the Company's rate proposals will likely only exacerbate the burdens felt by low-income low-use households. A subsidy limited to SNAP-qualified customers is small relief for regressive rate impacts that would impact 200,000 residential customers. The proposal is not reasonable.

Q. What is the likely result of the increase in fixed residential customer charges?

A. The increase in fixed residential customer charges will increase the number of Florida households living in energy poverty, and increase the demand for energy assistance funding support. Since energy assistance payments are made on behalf of customers directly to the utility, an increase in energy assistance payments means an increase in such revenues from the State or Federal government paid directly to the Company.

IMPACTS ON ENERGY EFFICIENCY AND CLEAN ENERGY

Q. How does increasing fixed customer charges specifically impact customer investment in energy efficiency and conservation?

A. Increases in fixed customer charges create powerful price signals ***against*** investment in energy efficiency, which is inconsistent with stated Florida policy goals.

Q. Did the Company consider the impact of its proposed increase in the fixed customer charge on energy efficiency, conservation, and renewables?

A. The Company indicated that it expected a modest increase in electricity sales because of the proposed residential rate restructuring, but that these sales would be offset by proposed new energy efficiency programs. (*See* witness Park direct testimony at page 22, lines 8-16). Company witness McGee testified that the proposed reduction in volumetric charges would make more energy efficiency programs cost effective under the Ratepayer Impact Measure test. Company witness Floyd provided data, at Exhibit JNF-1, Schedule 3, showing that these new program offerings could save about 3.3 GWh of energy at the meter on average out to the year 2024. Witness McGee stated that savings would be about 3.5 GWh in his direct testimony at page 20, lines 17-18.

Q. How does the potential savings of these expanded programs compare to the broader context of energy efficiency efforts at the Company?

A. First it should be noted that the Company's 2013 Savings were 87 GWh total (gross @ meter) or about 64 GWh in residential savings (calculated from 2013 Annual FEECA Program Progress Report, attached as Exhibit KRR-13). The Company's 2015 Savings were substantially less at 59 GWh total, or 46 GWh residential (calculated from 2015 Annual FEECA Program Progress Report, attached as Exhibit KRR-14). Looking forward, the Commission-approved residential savings goal for 2017 is only 4.2 GWh, which with the addition of the proposed 3.3GWh, would total only 7.5 GWh. In this context, the added energy efficiency programs will only slightly close the gap that was created by major reductions in energy efficiency programs over the past few years.

Q. How much energy efficiency would be required to offset not just increased sales due to lower volumetric costs, but also increased bill burdens imposed through higher fixed charges?

A. The damage to energy efficiency potential that would be caused by the proposed rate restructuring is profound and shocking. As demonstrated in Figure KRR-7, the Company energy efficiency programs would have to reduce consumption by about 1,448 GWh in order to reduce customer bills by the amount that the proposed rate restructuring increases them. This represents an equivalent of 27% of total residential retail sales. The Company rate restructuring proposal must be viewed as a whole. The Company not only proposes to increase an already high fixed customer charge by 155%, but also proposes to structure the rate in a way that precludes any chance for customers to reduce the impact of the increase through changes in consumption. Worse still, the Company provides customers with no means to monitor or track consumption behavior even in the event that they choose one of the alternative rates proposed. The Company's rate restructuring proposals are the most pure form of an effort to extract monopoly rents that I have seen in a very long time.

Figure KRR-7: Equivalent Savings Necessary to Offset Impacts of Proposed Rate Restructuring

		Volumetric Charge per kWh		
	Daily Charge	Energy	All Charges	Non-Energy
Current	$ 0.62	$ 0.04585	$ 0.11359	$ 0.06774
Proposed	$ 1.58	$ 0.03298	$ 0.09667	$ 0.06369
Increase/ (Decrease)	$ 0.96	$ (0.01287)	$ (0.01692)	$ (0.00405)
% Increase/ Decrease	155%	-28%	-15%	-6%

$/YR increase in Daily Charge per Customer	$/YR increase in Fixed Charge as Equivalent kWh (proposed rates)	MWh Savings Required at Proposed Rates to Offset Impacts of Increased Fixed Charges	Total Annual MWh Sales Forecast to Residential Customers per MFR Sched. E6a	% Reduction in Annual Sales Needed to Offset Daily Charge Increase
$ 350.40	$ 3,625	1,448,960	5,336,892	27%

Source: Exhibit RLM-1, Schedule 1.

Q. Why should the Commission be concerned about approving a rate design that is detrimental to energy efficiency, conservation, and renewables?

A. Energy efficiency, conservation, and renewables offer many benefits to the people and State of Florida, and are stated goals in Florida law. These benefits include resource diversification, grid resiliency, future cost reductions associated with increased volume of deployment (economies of scale), job creation, system-wide cost reductions, and leveraging of non-utility investment dollars, among others.

Q. How do energy efficiency and conservation in particular, produce these benefits?

A. Energy efficiency and conservation generate benefits to the utility, ratepayers, and society in general in many ways, including lower cost than traditional generation and infrastructure investments, downward pressure on rates over the mid- and long-term, persistent and consistent savings, nearly endless resource potential due to economies of manufacturing scale and technological innovation, broad availability to all classes of customers, and significant externalized benefits often not accounted for in ratemaking.

Q. Can affected customers avoid fixed charges with more efficient energy use under the Company's proposal?

A. No. The proposed increase in fixed charges cannot be avoided by customer reductions in energy use. As described above, the only customer option for savings is to first offset the increased bill resulting from the increased fixed customer charge. Given the magnitude of the proposed increase in the fixed customers charge, it is practically impossible for the average residential customer to accomplish this.

Q. What do these changes mean to the energy savings opportunity for residential customers?

A. According to the Company, the average monthly consumption of its residential customers is 1,112 kWh per month. (*See* Exhibit RLM-1, Schedule 6). A customer would need to reduce their energy use by 302 kWh per month to avoid volumetric energy charges in an amount sufficient to offset the added bill impact of the proposed increased fixed charge. This would be equivalent to a reduction of 27% in household energy use for the average customer. The Company proposal is that the average customer must reduce consumption by 27% per year in order to offset the increased customer charge, against a rate that saves 15% *less* with each kWh avoided, due to the proposed reduction in the energy charge. The Company not only proposes to increase the non-bypassable customer charge, but also to reduce the opportunity to avoid its impact. The higher fixed charge is a non-bypassable connection tax that makes serious investment in energy efficiency less cost-effective from the customer's perspective.

Q. Do these proposed changes impact customers who have invested in energy efficiency improvements?

A. Yes. Fixed charges are "unavoidable" and reduce the marginal value and the ultimate bill value to those customers who have taken action to reduce their energy consumption. These changes will also have a chilling impact on customers who are contemplating such energy efficiency investments.

Q. How does a change to higher fixed charges and lower volumetric charges impact prior customer investments in energy efficiency?

A. Allocation of costs to fixed, non-bypassable charges imposes an extraordinary burden and destroys investment-backed savings expectations on low energy users who have made significant prior investments in order to lower their bills. Customers and communities that invested in weatherization, equipment improvements, and building remodeling did so both to save money at the then-existing rates as well as to reduce exposure to future rate increases.

By breaking with practices (as voiced by Bonbright and others) that have been long considered settled matters, the increased fixed charges and decreased volumetric rate is like a regulatory taking. Customers who have made good faith investments in greater efficiency based on established rates and ratemaking practices would experience significant and unfair bill increases under the Company's proposal.

As explained above, the Company's proposal is like taking 3,624 kWh per year out of the planned savings stream for those customers (based on 302 kWh per month multiplied by 12 months), extending the payback period they had planned upon and frustrating their investment economics. The proposed 15% reduction in the volumetric energy charge further compounds this problem by reducing the value of each saved kWh. This is irreversible damage to the customers that could be avoided without harm to the Company by simply allocating the revenues associated with the fixed charge increase to volumetric rates.

Q. Does the Company proposal to increase fixed customer charges take into consideration impacts on economic and energy efficiency?

A. The Company witnesses assert that more programs will pass the RIM test due to the lower volumetric rates proposed. Otherwise, the Company witnesses do not address impacts on either past or future energy efficiency investments. Rather, the Company appears single-mindedly focused on collecting sunk fixed costs through fixed customer charges. This backwards thinking focus creates regressive impacts.

Worse, it sends a signal to customers that it is not worth investing in energy efficiency, conservation, or demand reduction, and sets up the economically perverse situation in which customers are charged for creating demand and then given weak or ineffective price signals to mitigate that cost-causation in the future. The Company proposals create significant barriers and impediments to energy efficiency, conservation, and renewables that would result in improper discrimination and in rates that do not comport with sound energy policy.

Q. What is the ultimate impact of reduced energy efficiency, conservation, and development of renewable energy?

A. Inefficient use means uneconomically high levels of energy consumption. These in turn lead to demand for more expensive infrastructure. The costs of these investments are levied on consumers and raise their rates. Following the Company's logic in this rate application, a significant share of these costs would be allocated to fixed charges, creating higher non-bypassable charges. And so on. The Company proposal seems likely to start and accelerate a death spiral of electric service unaffordability.

THE OPTION OF RECOVERING REVENUES THROUGH VOLUMETRIC RATES

Q. Does the Company have alternatives to allocating increased costs to fixed customer charges?

A. Yes. A fixed customer charge is not the only mechanism for recovering fixed costs. Precisely because of the concerns that I summarized, utilities and regulators throughout the country have typically allocated a large proportion of fixed costs to volumetric rate elements for residential and small commercial customers. This process starts with a more reasonable basic customer cost approach to cost classification. The Company already uses a volumetric energy distribution charge that could help carry whatever revenue requirement is properly allocated to residential and commercial secondary customers, after backing out increases due to the minimum system and B&G methods.

Q. Does the use of volumetric rates to carry fixed costs present a financial integrity risk to the utility that should be remedied with higher fixed charges?

A. No. First, the ratemaking principle is that rates should reflect costs, not be perfectly aligned with cost structure. There is no statistical likelihood of any real risk to the Company's financial integrity due to some customers using less energy than the utility had forecast in the interval between rate cases. The adverse impact on low use, low income, and fixed income elderly customers, as well as the economics of efficient use of energy, outweighs any hypothetical risk to the Company's earnings.

Q. Does the Company address any other opportunities to reduce the adverse impacts of its proposed fixed customer charge proposals?

A. No. In particular, the Company does not assess the impact of allocating its proposed revenue requirements to volumetric distribution charges. The proposed change in fixed customer charges for residential customers seeks to recover about $68,169 million in additional revenue, and a 155% increase in the customer charge. This is an extreme rate shock, especially for low users, many of whom are low income customers. Instead, assigning the revenue requirement to the volumetric energy charge would spread the increase across all energy use and cause an increase in the volumetric charge of only 1.3 cents, or about 11% above current rates. This is still a large increase, but a much more gradual increase than that proposed, and one that also avoids the regressive impact on low-income and low-use customers.

This is only one option for rate design that could preserve price signals and mitigate regressive and bad policy impacts. Modification of the 1NCP cost allocator would also reduce the volumetric charge for residential customers and thus the ultimate rate impact. The Company's failure to evaluate the option of reliance upon a volumetric charge suggests an unreasonable preoccupation with sunk costs and insufficient focus on the prospective impacts of its proposed rates.

Q. Why is it appropriate to continue recovering fixed costs through volumetric rates?

A. It is appropriate because of the price signal function of properly designed rates. Properly designed rates *reflect* properly allocated costs *and* send signals for efficient consumption in the future. Sunk fixed costs, the focus of the Company's concern in its customer charge proposal, can be reflected in *either* the fixed charge or a volumetric charge. An efficient price signal relating to future fixed costs can *only* be communicated with a volumetric charge. That is why a volumetric charge is the optimal rate design in this case.

Q. Does volumetric charge recovery of fixed costs violate principles of ratemaking or sub-optimize the economic efficiency of rates?

A. No. Sound ratemaking is based on ensuring that costs are properly allocated to customer classes based on cost causation. I know of no ratemaking or economic principle that finds that cost *structure* must be replicated in rate *design*, especially when significant negative policy impacts are attendant to that approach. Traditional ratemaking limits customer charges to certain basic customer connection costs—the meter, billing services, and other similar general and administrative costs. These are fixed costs that vary by customer count and typically form the basis and limit for fixed customer charges. Even so, when the policy impacts discussed above are considered, some of these costs are collected through variable charges.

Q. When costs associated with distribution systems are classified as fixed, should they be collected through the fixed customer charge?

A. Not necessarily, and not if the result is that low-usage customers are disproportionately impacted or that adverse impacts on energy efficiency, conservation, and renewables also result. Recently in other states, some utilities have argued that increased fixed customer charges secure revenue recovery in a world where customers have more options to reduce their level of usage. I am not aware of any evidence or analysis, and see none in this record, that increasing fixed customer charges improves system-wide economic efficiency or the efficiency of *customer* decisions. Absent evidence of system-wide or customer efficiency benefits, fixed customer charges should not be increased and costs should instead be allocated to variable charges. Again, the differences in costs that lead to labeling them as fixed or variable do not, standing alone, tell us anything about the rate design that should be used to recover them.

Q. What is the key difference between fixed and variable costs?

A. The key discriminator for labeling a cost as fixed or variable is the element of time. It is important to remember that over the long term, all costs are variable; just as over the very short term, one could argue all costs are fixed. For example, distribution transformers are typically treated as a fixed cost because of their relatively long life. Loading on a transformer, especially during periods of high demand, will impact its useful life. As a result, demand reductions can extend the useful life of transformers.

Q. How do residential customers exercise control over their variable and fixed costs?

A. The benefit of using volumetric rates to recover both fixed and variable costs is that class costs are still properly reflected in rates, and that customers have meaningful, practical, and realistic opportunities to exercise control over their energy bills and costs. Reductions in use—through efficiency, conservation, or self-generation—all contribute to reductions in variable energy costs. Moreover, these behaviors also reduce high peak demand, and by doing so customers directly contribute to reduced fixed costs going forward. Efficiency, demand response, west-facing solar, and other options allow customers to contribute to fixed cost reduction, and all of these are frustrated by shifting cost recovery from volumetric to fixed charges, as proposed by the Company.

Q. If the utility has costs that it classifies as fixed, should the charge to recover those costs be a fixed charge, in order to send a price signal to customers?

A. No. There is no meaningful price signal in charging a rate that few if any customers can effectively respond to with modification in behavior. Residential and small commercial customers have only limited options for changing their demand independently of their energy use; so volumetric energy rates are the best rate design option for sending price signals for both energy and demand cost causation on a going-forward basis. A customer's demand, especially for low-income and low-use customers, is a function of the energy performance of their home, which is often rented; their major appliances, which are often expensive to replace or upgrade; and the weather. Imposing high fixed costs on these customers is the economic regulation equivalent of suggesting to customers, "Let them eat cake."

Q. What is your recommendation for a rate design that would recover increased costs that the Company proposes to collect through increased fixed customer charges?

A. The prudent costs that the Company proposes to allocate to fixed customer charges should be allocated to volumetric rate elements unless and until the Company demonstrates the reasonableness of its proposed rate design in light of the potential adverse impacts discussed, and after consideration of the relative impacts of alternative rate designs.

Q. Do increased fixed charges impact volumetric charges?

A. Yes. The Company proposes in this case a direct shift of volumetric revenues to fixed customer charges. Allocating costs to fixed charges means that these costs are not allocated to volumetric charges. Volume of consumption is the most important aspect of electricity over which customers have control, so long as they choose to take any service at all. Lower volumetric charges weaken the short- and mid-term price signal customers receive relating to their consumption. In this way, increased fixed charges are economically equivalent to and exacerbate the uneconomic behavior encouraged by declining block electric rates.

Q. What impact does the combination of higher fixed charges and lower volumetric charges have on consumption behavior, and what does that mean for rates?

A. Allocation of costs to fixed, non-bypassable charges instead of volumetric charges reinforces the very consumption behavior that drives revenue requirements higher. Lower volumetric charges send a weaker signal to customers to take the kind of action that can, over the long term, reduce coincident peak demand and production, and transmission costs. Again, increased fixed charges are economically equivalent to and exacerbate the uneconomic behavior encouraged by declining block electric rates.

Q. Are there other options for the Company to explore in rate restructuring?

A. Yes. Other options include much more careful analysis of the B&G method.

- If the Company believes customers would like a higher fixed monthly charge in order to obtain an improvement in monthly bill stability, they should offer the rate in a limited pilot, alongside rates like the optional 3-part rate with demand charges.

- If the Company believes there are inequitable intra-class subsidies under current rates, it should conduct the data collection and analysis to substantiate its beliefs. If the subsidies exist, the Company could propose class segmentation to address these inequities.
- The Company has existing optional time-varying rates, including a time of use rate and an experimental critical peak pricing rate. If the Company believes that it is important to engage customers in demand cost reducing behavior, it could evaluate whether one of these rates should be made the standard rate (while retaining the current standard rate as an option). Of course, such rates would be highly ineffective unless customers were also provided real-time information about consumption and technology with which to control and reduce load.
- Another method for engaging customers in demand cost reducing behavior would be for the Company to foster the expansion of demand response and demand reduction aggregation programs.

These and other options would address the root causes that are driving the Company's efforts to restructure rates, but without regressive and punitive impacts on customers facing the highest energy burdens. Finally, the Company could propose a comprehensive agenda of utility transformation in order to address the fundamental financial flaws in the throughput-based business model the utility currently operates under.

Q. Does the Company have adequate systems in place to enable customers to respond to rates?

A. No. The Company has expressed intentions to provide customers with historical and, eventually, real-time information about demand at some unspecified point in the future.

But adding insult to bill injury, the Company proposed to roll out even optional demand charge and time-variable rates without also providing customers with the tools to effectively manage their energy use. The Company must deploy customer functionality before it deploys rates that are built around responses to price signals. Otherwise the Company is proposing nothing more than the extraction of monopoly rents.

THE BIGGER PICTURE

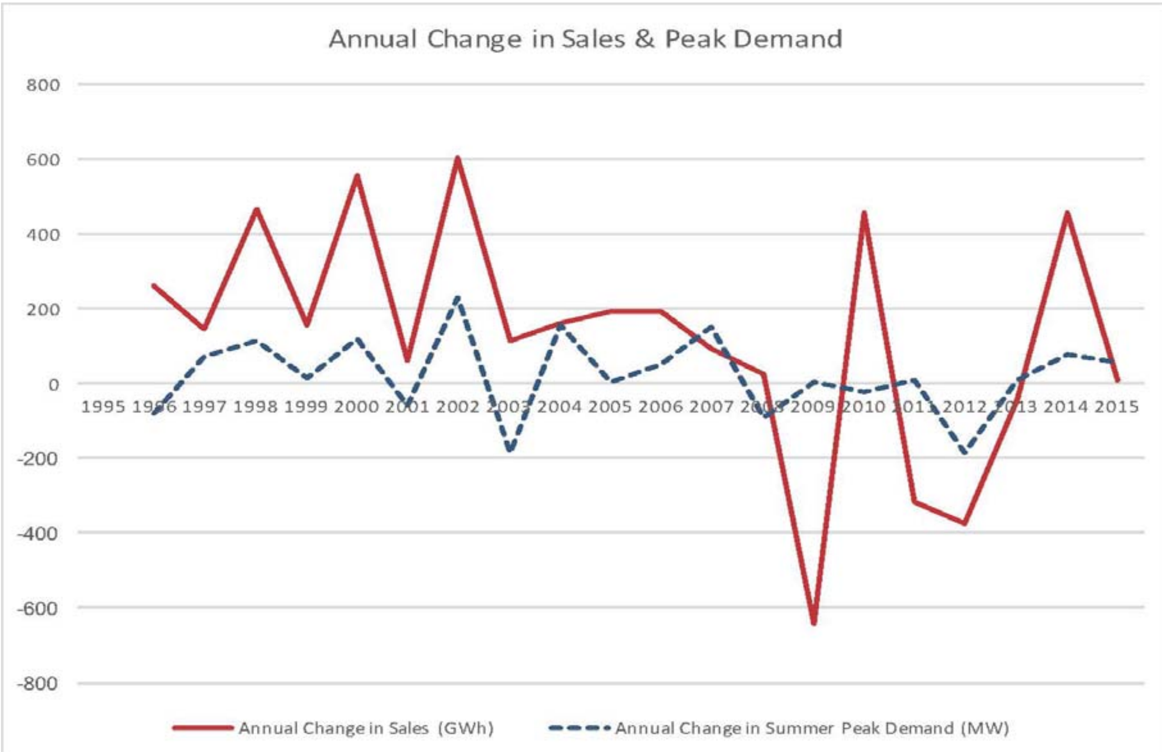
Q. Is there a broader context that explains the Company's effort to impose such regressive and unjustified residential rate changes?

A. The Company finds itself in a similar situation as many electric utilities in the United States and around the world. The Company is operating under a business model that brings profitability and shareholder wealth only with relatively constant increases in throughput—sales of kilowatt hours.

Q. What have been the long-term trends in energy sales and demand for the Company?

A. Based on data in the Company's 10-year site plans, the real volatility problem is in changes in energy sales and demand over the past 20 years. Figure KRR-8 shows that while there were major changes in and around the economic recession in 2008, the Company has long been impacted by severe volatility in energy and demand.

Figure KRR-8: Year over Year Changes in Retail Sales and Peak Summer Demand



Source: Gulf Power Company 10-years Plans for 2005, 2010, 2016.

Q. Given this volatility, is it reasonable for the Company to attempt to stabilize its revenues through the implementation of a massive increase in fixed customer charges and a shifting of fixed demand-related costs to the customer component of costs?

A. No. It is understandable that the Company would try to fix its larger problems with rate restructuring, but it is not reasonable. The sales and demand volatility that the Company faces can only be addressed by focusing on the root causes of that volatility, and not upon the revenue flow symptoms.

Q. Where should the Company commit its focus, in order to address the root causes of its sales and demand volatility?

A. The Company should be working with customers to improve overall load factor through deep dive energy efficiency and demand reduction programs. The Company should expand its efforts beyond the few thousands of customers it identifies as potential participants in its expanded DSM programs and seek transformational change in the way its customers use energy. Punitive rate restructuring that gives customers no real control over a large fraction of their bills is counterproductive to this transformation. The evidence does not demonstrate a significant residential intra-class subsidy problem. A simple review of the facts does show that the Company has a serious sales and demand volatility problem. On behalf of the public interest and the Company's shareholders, the Company should address the core causes of its problems and not just propose a rate design band aid.

CONCLUSION

Q. What are your findings regarding the Company fixed customer charge proposals?

A. My findings are summarized as follows:

- The Company's proposal to expand the scope of fixed customer charges for residential rate classes to include demand charges is at odds with long-established principles of regulatory ratemaking practice.
- The Company has offered a deeply flawed and unsubstantiated argument in an effort to justify an unprecedented request to increase fixed customer charges for residential rate classes.
- The Company has selected cost classification and allocation methods that result in unreasonably high customer costs for residential customers.
- The Company has proposed a low-income subsidy program and enhanced energy efficiency programs that do not meaningfully address the many problems that would be created by the proposed residential rate restructuring.

- The Company has failed to adequately consider the adverse impacts that its proposed fixed customer charges would have on low income customers, economic efficiency, energy efficiency, conservation, and renewable energy.

Q. How would you describe the Company proposal in broad economic terms?

A. The Company seeks the Commission's assistance in monopoly rent-seeking. That is, the Company wants to increase its wealth via guaranteed returns granted by the Commission through fixed customer charges that flow from a series of cost classification and allocation proposals.

Q. Why does it matter that the Company has not justified its rate design proposals regarding fixed customer charges?

A. The decisions about how to allocate class costs to rates through rate design involve important concerns relating to affordability, price signals, and congruence with state energy policy. The Company's foundation for its residential rate proposals is inadequate in light of the significant repercussions for customers and the State generally, and it is therefore neither just nor reasonable. In my opinion, the Company's proposals fail to meet the legal and regulatory burden the Company faces, and should be disapproved.

RECOMMENDATIONS

Q. What are your recommendations to the Commission?

A. Based on my review of the evidence in this case, I make several recommendations:

- The Commission should not approve the Company's proposal to increase fixed customer charges applicable to Residential customers, and should direct that any approved revenue requirement associated with those proposed rate changes be allocated to the volumetric energy charges.
- The Commission should not approve the Company's use of the minimum system

approach for classifying customer costs and should direct the Company to employ an approach that assigns to the customer cost category those costs that vary solely or predominantly with changes in the customer count.

- The Commission should not approve the Company's proposal to use a 1NCP allocator for demand-related distribution costs, and should direct the Company to evaluate allocators that use many more hours in the non-coincident peak of customer classes or groups.

Q. Does this conclude your testimony?

A. Yes.

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Summary

Nationally recognized leader and innovator in electricity and energy law, policy, and regulation. Experienced as a public utility regulatory commissioner, educator, research and development program manager, utility executive, business builder, federal executive, corporate sustainability leader, consultant, and advocate. Highly proficient in advising, managing, and interacting with government agencies and committees, the media, citizen groups, and business associations. Successful track record of working with US Congress, state legislatures, governors, regulators, city councils, business leaders, researchers, academia, and community groups. National and international contacts through experience with Pace Energy and Climate Center, Austin Energy, AES Corporation, US Department of Energy, Texas Public Utility Commission, Jicarilla Apache Tribal Utility Authority, Cargill Dow LLC (now NatureWorks, LLC), Rocky Mountain Institute, CH2M HILL, Houston Advanced Research Center, Environmental Defense Fund, and others. Skilled attorney, negotiator, and advisor with more than twenty-five years of experience working with diverse stakeholder communities in electricity policy and regulation, emerging energy markets development, clean energy technology development, electric utility restructuring, smart grid development, and the implementation of sustainability principles. Extensive regulatory practice experience. Nationally recognized speaker on energy, environment and sustainable development matters. Managed staff as large as 250; responsible for operations of research facilities with staff in excess of 600. Developed and managed budgets in excess of $300 million. Law teaching experience at Pace University School of Law, University of Houston Law Center, and U.S. Military Academy at West Point. Post-doctorate degrees in environmental and military law. Military veteran.

Employment

PACE ENERGY AND CLIMATE CENTER, PACE UNIVERSITY SCHOOL OF LAW

Executive Director: May 2014—Present.

Leader of a team of professional and technical experts in energy and climate law, policy, and regulation. Secure funding for and manage execution of research, market development support, and advisory services for a wide range of funders, clients, and stakeholders with the overall goal of advancing clean energy deployment, climate responsibility, and market efficiency. Supervise a team of employees, consultants, and adjunct researchers. Provide learning and development opportunities for law students. Coordinate efforts of the Center with and support the environmental law faculty. Additional activities:

- Co-Director and Principal Investigator, Northeast Solar Energy Market Coalition (2015-present). The NESEMC is a US Department of Energy's SunShot Initiative Solar Market Pathways project. Funded under a cooperative agreement between the US DOE and Pace University, the NESEMC seeks to harmonize solar market policy and advance best policy and regulatory practices in the northeast United States.
- Chairman of the Board, Center for Resource Solutions (1997-present). CRS is a not-for-profit organization based at the Presidio in California. CRS developed and manages the Green-e Renewable Electricity Brand, a nationally and internationally recognized branding program

for green power and green pricing products and programs. Past chair of the Green-e Governance Board (formerly the Green Power Board).

- Director, Interstate Renewable Energy Council (IREC) (2012-present). IREC focuses on issues impacting expanded renewable energy use such as rules that support renewable energy and distributed resources in a restructured market, connecting small-scale renewables to the utility grid, developing quality credentials that indicate a level of knowledge and skills competency for renewable energy professionals.

RÁBAGO ENERGY LLC

Principal: July 2012—Present. Consulting practice dedicated to providing expert witness and policy formulation advice and services to organizations in the clean and advanced energy sectors. Recognized national leader in development and implementation of award-winning "Value of Solar" alternative to traditional net metering. Additional information at www.rabagoenergy.com.

AUSTIN ENERGY – THE CITY OF AUSTIN, TEXAS

Vice President, Distributed Energy Services: April 2009—June 2012. Executive in 8th largest public power electric utility serving more than one million people in central Texas. Responsible for management and oversight of energy efficiency, demand response, and conservation programs; low-income weatherization; distributed solar and other renewable energy technologies; green buildings program; key accounts relationships; electric vehicle infrastructure; and market research and product development. Executive sponsor of Austin Energy's participation in an innovative federally-funded smart grid demonstration project led by the Pecan Street Project. Led teams that successfully secured over $39 million in federal stimulus funds for energy efficiency, smart grid, and advanced electric transportation initiatives. Additional activities included:

- Director, Renewable Energy Markets Association. REMA is a trade association dedicated to maintaining and strengthening renewable energy markets in the United States.
- Membership on Pedernales Electric Cooperative Member Advisory Board. Invited by the Board of Directors to sit on first-ever board to provide formal input and guidance on energy efficiency and renewable energy issues for the nation's largest electric cooperative.

THE AES CORPORATION

Director, Government & Regulatory Affairs: June 2006—December 2008. Government and regulatory affairs manager for AES Wind Generation, one of the largest wind companies in the country. Manage a portfolio of regulatory and legislative initiatives to support wind energy market development in Texas, across the United States, and in many international markets. Active in national policy and the wind industry through work with the American Wind Energy Association as a participant on the organization's leadership council. Also served as Managing Director, Standards and Practices, for Greenhouse Gas Services, LLC, a GE and AES venture committed to generating and marketing greenhouse gas credits to the U.S. voluntary market. Authored and implemented a standard of practice based on ISO 14064 and industry best practices. Commissioned the development of a suite of methodologies and tools for various greenhouse gas credit-producing technologies. Also served as Director, Global Regulatory Affairs, providing regulatory support and group management to AES's international electric utility operations on five continents. Additional activities:

- Director and past Chair, Jicarilla Apache Nation Utility Authority (1998 to 2008). Located in New Mexico, the JAUA is an independent utility developing profitable and autonomous utility services that provides natural gas, water utility services, low income housing, and energy planning for the Nation. Authored "First Steps" renewable energy and energy efficiency strategic plan.

HOUSTON ADVANCED RESEARCH CENTER

Group Director, Energy and Buildings Solutions: December 2003—May 2006. Leader of energy and building science staff at a mission-driven not-for-profit contract research organization based in The Woodlands, Texas. Responsible for developing, maintaining and expanding upon technology development, application, and commercialization support programmatic activities, including the Center for Fuel Cell Research and Applications, an industry-driven testing and evaluation center for near-commercial fuel cell generators; the Gulf Coast Combined Heat and Power Application Center, a state and federally funded initiative; and the High Performance Green Buildings Practice, a consulting and outreach initiative. Secured funding for major new initiative in carbon nanotechnology applications in the energy sector. Developed and launched new and integrated program activities relating to hydrogen energy technologies, combined heat and power, distributed energy resources, renewable energy, energy efficiency, green buildings, and regional clean energy development. Active participant in policy development and regulatory implementation in Texas, the Southwest, and national venues. Frequently engaged with policy, regulatory, and market leaders in the region and internationally. Additional activities:

- President, Texas Renewable Energy Industries Association. As elected president of the statewide business association, leader and manager of successful efforts to secure and implement significant expansion of the state’s renewable portfolio standard as well as other policy, regulatory, and market development activities.
- Director, Southwest Biofuels Initiative. Established the Initiative acts as an umbrella structure for a number of biofuels related projects, including emissions evaluation for a stationary biodiesel pilot project, feedstock development, and others.
- Member, Committee to Study the Environmental Impacts of Windpower, National Academies of Science National Research Council. The Committee was chartered by Congress and the Council on Environmental Quality to assess the impacts of wind power on the environment.
- Advisory Board Member, Environmental & Energy Law & Policy Journal, University of Houston Law Center.

CARGILL DOW LLC (NOW NATUREWORKS, LLC)

Sustainability Alliances Leader: April 2002—December 2003. Founded in 1997, NatureWorks, LLC is based in Minnetonka, Minnesota. Integrated sustainability principles into all aspects of a ground-breaking biobased polymer manufacturing venture. Responsible for maintaining, enhancing and building relationships with stakeholders in the worldwide sustainability community, as well as managing corporate and external sustainability initiatives. NatureWorks is the first company to offer its customers a family of polymers (polylactide – “PLA”) derived entirely from annually renewable resources with the cost and performance necessary to compete with packaging materials and traditional fibers; now marketed under the brand name “Ingeo.”

- Successfully completed Minnesota Management Institute at University of Minnesota Carlson School of Management, an alternative to an executive MBA program that surveyed fundamentals and new developments in finance, accounting, operations management, strategic planning, and human resource management.

ROCKY MOUNTAIN INSTITUTE

Managing Director/Principal: October 1999–April 2002. In two years, co-led the team and grew annual revenues from approximately $300,000 to more than $2 million in annual grant and consulting income. Co-authored “Small Is Profitable,” a comprehensive analysis of the benefits of distributed energy resources. Worked to increase market opportunities for clean and distributed energy resources through consulting, research, and publication activities. Provided consulting and advisory services to help business and government clients achieve sustainability through application and incorporation of Natural Capitalism principles. Frequent appearance in media at international, national, regional and local levels.

- President of the Board, Texas Ratepayers Organization to Save Energy. Texas R.O.S.E. is a non-profit organization advocating low-income consumer issues and energy efficiency programs.
- Co-Founder and Chair of the Advisory Board, Renewable Energy Policy Project-Center for Renewable Energy and Sustainable Technology. REPP-CREST was a national non-profit research and internet services organization.

CH2M HILL

Vice President, Energy, Environment and Systems Group: July 1998–August 1999. Responsible for providing consulting services to a wide range of energy-related businesses and organizations, and for creating new business opportunities in the energy industry for an established engineering and consulting firm. Completed comprehensive electric utility restructuring studies for the states of Colorado and Alaska.

PLANERGY

Vice President, New Energy Markets: January 1998–July 1998. Responsible for developing and managing new business opportunities for the energy services market. Provided consulting and advisory services to utility and energy service companies.

ENVIRONMENTAL DEFENSE FUND

Energy Program Manager: March 1996–January 1998. Managed renewable energy, energy efficiency, and electric utility restructuring programs for a not-for-profit environmental group with a staff of 160 and over 300,000 members. Led regulatory intervention activities in Texas and California. In Texas, played a key role in crafting Deliberative Polling processes. Initiated and managed nationwide collaborative activities aimed at increasing use of renewable energy and energy efficiency technologies in the electric utility industry, including the Green-e Certification Program, Power Scorecard, and others. Participated in national environmental and energy advocacy networks, including the Energy Advocates Network, the National Wind Coordinating Committee, the NCSL Advisory Committee on Energy, and the PV-COMPACT Coordinating Council. Frequently appeared before the Texas Legislature, Austin City Council, and regulatory commissions on electric restructuring issues.

UNITED STATES DEPARTMENT OF ENERGY

Deputy Assistant Secretary, Utility Technologies: January 1995–March 1996. Manager of the Department's programs in renewable energy technologies and systems, electric energy systems, energy efficiency, and integrated resource planning. Supervised technology research, development and deployment activities in photovoltaics, wind energy, geothermal energy, solar thermal energy, biomass energy, high-temperature superconductivity, transmission and distribution, hydrogen, and electric and magnetic fields. Developed, coordinated, and advised on legislation, policy, and renewable energy technology development within the Department, among other agencies, and with Congress. Managed, coordinated, and developed international agreements for cooperative activities in renewable energy and utility sector policy, regulation, and market development between the Department and counterpart foreign national entities. Established and enhanced partnerships with stakeholder groups, including technology firms, electric utility companies, state and local governments, and associations. Supervised development and deployment support activities at national laboratories. Developed, advocated and managed a Congressional budget appropriation of approximately $300 million.

STATE OF TEXAS

Commissioner, Public Utility Commission of Texas. May 1992–December 1994. Appointed by Governor Ann W. Richards. Regulated electric and telephone utilities in Texas. Laid the groundwork for legislative and regulatory adoption of integrated resource planning, electric utility restructuring, and significantly increased use of renewable energy and energy efficiency resources. Co-chair and organizer of the Texas Sustainable Energy Development Council. Vice-Chair of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Energy Conservation. Member and co-creator of the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology (PV-COMPACT). Member, Southern States Energy Board Integrated Resource Planning Task Force. Member of the University of Houston Environmental Institute Board of Advisors.

LAW TEACHING

Professor for a Designated Service: Pace University Law School, 2014-present. Non-tenured member of faculty. Courses taught: Energy Law. Supervise a student clinical effort that engages in a wide range of advocacy, analysis, and research activities in support of the mission of the Pace Energy and Climate Center.

Associate Professor of Law: University of Houston Law Center, 1990–1992. Full time, tenure track member of faculty. Courses taught: Criminal Law, Environmental Law, Criminal Procedure, Environmental Crimes Seminar, Wildlife Protection Law. Provided *pro bono* legal services in administrative proceedings and filings at the Texas Public Utility Commission.

Assistant Professor: United States Military Academy, West Point, New York, 1988–1990. Member of the faculty in the Department of Law. Honorably discharged in August 1990, as Major in the Regular Army. Courses taught: Constitutional Law, Military Law, and Environmental Law Seminar. Greatly expanded the environmental law curriculum and laid foundation for the concentration program in law. While carrying a full time teaching load, earned a Master of Laws degree in Environmental Law. Established a program for subsequent environmental law professors to obtain an LL.M. prior to joining the faculty.

LITIGATION

Trial Defense Attorney and Prosecutor, U.S. Army Judge Advocate General's Corps, Fort Polk, Louisiana, January 1985–July 1987. Assigned to Trial Defense Service and Office of the Staff Judge Advocate. Prosecuted and defended more than 150 felony-level courts-martial. As prosecutor, served as legal officer for two brigade-sized units (approximately 5,000 soldiers), advising commanders on appropriate judicial, non-judicial, separation, and other actions. Pioneered use of some forms of psychiatric and scientific testimony in administrative and judicial proceedings.

NON-LEGAL MILITARY SERVICE

Armored Cavalry Officer, 2d Squadron 9th Armored Cavalry, Fort Stewart, Georgia, May 1978–August 1981. Served as Logistics Staff Officer (S-4). Managed budget, supplies, fuel, ammunition, and other support for an Armored Cavalry Squadron. Served as Support Platoon Leader for the Squadron (logistical support), and as line Platoon Leader in an Armored Cavalry Troop. Graduate of Airborne and Ranger Schools. Special training in Air Mobilization Planning and Nuclear, Biological and Chemical Warfare.

Formal Education

LL.M., Environmental Law, Pace University School of Law, 1990: Curriculum designed to provide breadth and depth in study of theoretical and practical aspects of environmental law. Courses included: International and Comparative Environmental Law, Conservation Law, Land Use Law, Seminar in Electric Utility Regulation, Scientific and Technical Issues Affecting Environmental Law, Environmental Regulation of Real Estate, Hazardous Wastes Law. Individual research with Hudson Riverkeeper Fund, Garrison, New York.

LL.M., Military Law, U.S. Army Judge Advocate General's School, 1988: Curriculum designed to prepare Judge Advocates for senior level staff service. Courses included: Administrative Law, Defensive Federal Litigation, Government Information Practices, Advanced Federal Litigation, Federal Tort Claims Act Seminar, Legal Writing and Communications, Comparative International Law.

J.D. with Honors, University of Texas School of Law, 1984: Attended law school under the U.S. Army Funded Legal Education Program, a fully funded scholarship awarded to 25 or fewer officers each year. Served as Editor-in-Chief (1983–84); Articles Editor (1982–83); Member (1982) of the Review of Litigation. Moot Court, Mock Trial, Board of Advocates. Summer internship at Staff Judge Advocate's offices. Prosecuted first cases prior to entering law school.

B.B.A., Business Management, Texas A&M University, 1977: ROTC Scholarship (3–yr). Member: Corps of Cadets, Parson's Mounted Cavalry, Wings & Sabers Scholarship Society, Rudder's Rangers, Town Hall Society, Freshman Honor Society, Alpha Phi Omega service fraternity.

Selected Publications

"Achieving very high PV penetration – The need for an effective electricity remuneration framework and a central role for grid operators," Richard Perez (corresponding author), Energy Policy, Vol. 96, pp. 27-35 (2016).

"The Net Metering Riddle," Electricity Policy.com, April 2016.

"The Clean Power Plan," Power Engineering Magazine (invited editorial), Vol. 119, Issue 12 (Dec. 2, 2015)

"The 'Sharing Utility:' Enabling & Rewarding Utility Performance, Service & Value in a Distributed Energy Age," co-author, 51st State Initiative, Solar Electric Power Association (Feb. 27, 2015)

"Rethinking the Grid: Encouraging Distributed Generation," Building Energy Magazine, Vol. 33, No. 1 Northeast Sustainable Energy Association (Spring 2015)

"The Value of Solar Tariff: Net Metering 2.0," The ICER Chronicle, Ed. 1, p. 46 [International Confederation of Energy Regulators] (December 2013)

"A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," co-author, Interstate Renewable Energy Council (October 2013)

"The 'Value of Solar' Rate: Designing an Improved Residential Solar Tariff," Solar Industry, Vol. 6, No. 1 (Feb. 2013)

"A Review of Barriers to Biofuels Market Development in the United States," 2 Environmental & Energy Law & Policy Journal 179 (2008)

"A Strategy for Developing Stationary Biodiesel Generation," Cumberland Law Review, Vol. 36, p.461 (2006)

"Evaluating Fuel Cell Performance through Industry Collaboration," co-author, Fuel Cell Magazine (2005)

"Applications of Life Cycle Assessment to NatureWorks™ Polylactide (PLA) Production," co-author, Polymer Degradation and Stability 80, 403-19 (2003)

"An Energy Resource Investment Strategy for the City of San Francisco: Scenario Analysis of Alternative Electric Resource Options," contributing author, Prepared for the San Francisco Public Utilities Commission, Rocky Mountain Institute (2002)

"Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size," co-author, Rocky Mountain Institute (2002)

"Socio-Economic and Legal Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado," with Thomas E. Feiler, Colorado Public Utilities Commission and Colorado Electricity Advisory Panel (April 1, 1999)

"Study of Electric Utility Restructuring in Alaska," with Thomas E. Feiler, Legislative Joint Committee on electric Restructuring and the Alaska Public Utilities Commission (April 1, 1999)

"New Markets and New Opportunities: Competition in the Electric Industry Opens the Way for Renewables and Empowers Customers," EEBA Excellence (Journal of the Energy Efficient Building Association) (Summer 1998)

"Building a Better Future: Why Public Support for Renewable Energy Makes Sense," Spectrum: The Journal of State Government (Spring 1998)

"The Green-e Program: An Opportunity for Customers," with Ryan Wiser and Jan Hamrin, Electricity Journal, Vol. 11, No. 1 (January/February 1998)

"Being Virtual: Beyond Restructuring and How We Get There," Proceedings of the First Symposium on the Virtual Utility, Klewer Press (1997)

"Information Technology," Public Utilities Fortnightly (March 15, 1996)

"Better Decisions with Better Information: The Promise of GIS," with James P. Spiers, Public Utilities Fortnightly (November 1, 1993)

"The Regulatory Environment for Utility Energy Efficiency Programs," Proceedings of the Meeting on the Efficient Use of Electric Energy, Inter-American Development Bank (May 1993)

"An Alternative Framework for Low-Income Electric Ratepayer Services," with Danielle Jaussaud and Stephen Benenson, Proceedings of the Fourth National Conference on Integrated Resource Planning, National Association of Regulatory Utility Commissioners (September 1992)

"What Comes Out Must Go In: The Federal Non-Regulation of Cooling Water Intakes Under Section 316 of the Clean Water Act," Harvard Environmental Law Review, Vol. 16, p. 429 (1992)

"Least Cost Electricity for Texas," State Bar of Texas Environmental Law Journal, Vol. 22, p. 93 (1992)

"Environmental Costs of Electricity," Pace University School of Law, Contributor–Impingement and Entrainment Impacts, Oceana Publications, Inc. (1990)

Table of Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, and through Rábago Energy LLC

(as of 1 January 2017)

Date	Proceeding	Case/Docket #	On Behalf Of:
Dec. 21, 2012	VA Electric & Power Special Solar Power Tariff	Virginia SCC Case # PUE-2012-00064	Southern Environmental Law Center
May 10, 2013	Georgia Power Company 2013 IRP	Georgia PSC Docket # 36498	Georgia Solar Energy Industries Association
Jun. 23, 1203	Louisiana Public Service Commission Re-examination of Net Metering Rules	Louisiana PSC Docket # R-31417	Gulf States Solar Energy Industries Association
Aug. 29, 2013	DTE (Detroit Edison) 2013 Renewable Energy Plan Review (Michigan)	Michigan PUC Case # U-17302	Environmental Law and Policy Center
Sep. 5, 2013	CE (Consumers Energy) 2013 Renewable Energy Plan Review (Michigan)	Michigan PUC Case # U-17301	Environmental Law and Policy Center
Sep. 27, 2013	North Carolina Utilities Commission 2012 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 136	North Carolina Sustainable Energy Association
Oct. 18, 2013	Georgia Power Company 2013 Rate Case	Georgia PSC Docket # 36989	Georgia Solar Energy Industries Association
Nov. 4, 2013	PEPCO Rate Case (District of Columbia)	District of Columbia PSC Formal Case # 1103	Grid 2.0 Working Group & Sierra Club of Washington, D.C.
Apr. 24, 2014	Dominion Virginia Electric Power 2013 IRP	Virginia SCC Case # PUE-2013-00088	Environmental Respondents
May 7, 2014	Arizona Corporation Commission Investigation on the Value and Cost of Distributed Generation	Arizona Corporation Commission Docket # E-00000J-14-0023	Rábago Energy LLC (invited presentation and workshop participation)
Jul. 10, 2014	North Carolina Utilities Commission 2014 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 140	Southern Alliance for Clean Energy
Jul. 23, 2014	Florida Energy Efficiency and Conservation Act, Goal Setting – FPL, Duke, TECO, Gulf	Florida PSC Docket # 130199-EI, 130200-EI, 130201-EI, 130202-EI	Southern Alliance for Clean Energy
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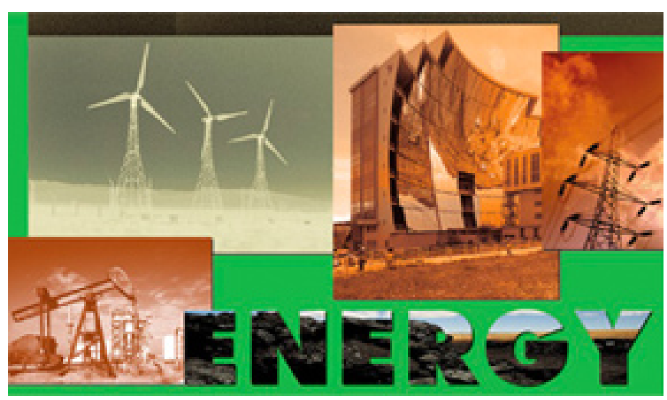

Principles of Public Utility Rates

JAMES C. BONBRIGHT

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To Martha

PREFACE

"I must admit that I possess no instinct by which to know the 'reasonable' from the 'unreasonable' in prices and must seek some conscious design for decision." Justice Jackson, dissenting, *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 at 645 (1944).

Public utilities, including railroads, conduct their business under a legal duty to supply satisfactory service at rates that are "reasonable" and not "unduly discriminatory." But what attributes must their rates possess in order to meet this twofold standard of validity? This is a question with which I have long been concerned from the standpoint of an economist, alike in the university classroom, as a public official, and as a participant in disputed rate cases. Having written from time to time on particular aspects of this many-sided question, I am now surveying the subject in a more comprehensive manner. But the survey is not a descriptive treatise on public utility rates or rate regulation. Instead, it is designed to complement the existing treatises by centering attention on the basic criteria of reasonable rates rather than on the many problems of application and administration.

In writing this book it has been my hope to make some contribution toward bridging the wide gap which unfortunately exists in this country between the thinking of the academic economists and that of the actual rate makers and rate regulators with respect to the goals of rate-making policy. As an economist, my own views are naturally colored by those of my profession. But I have tried to present these views in a form understandable to readers outside this profession, and with an awareness that rate-making practice must be governed partly by considerations foreign to the more abstract types of utility rate theory.

The major theme of the entire book, first set forth in Chapter II and developed in the following chapter, can here be stated briefly. Reasonable public utility rates, like reasonable prices in general, are rates designed to perform with reasonable effectiveness multiple functions as instruments of social control. But a system of rates that would be best designed to perform any one of these functions is unlikely also to be the best that could be designed to perform any of the others. Hence, to a substantial extent, sound rate-making policy is a policy of reasonable compromise among partly conflicting objectives.

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A word is in order as to the division of the twenty chapters into three major parts. The textbooks on public utility economics, as well as the actual rate cases before courts and commissions, draw a primary distinction between the criteria of reasonable rate *levels* and the criteria of reasonable rate *structures* or rate differentials. This is an important distinction, and I have followed it in devoting Part Two to the former subject and Part Three to the latter. But cutting right across this distinction, the chapters of Part One (except for Chapter IX) will first review possible alternative or complementary standards and measures of reasonable or optimum rates that are germane to the whole field of rate making. The resulting threefold division of subject matter leads unavoidably to some repetition of earlier material in later chapters. But I trust that the insight to be gained from the cross-classification is worth its necessary cost.

In illustrating the basic principles of public utility rate making, I have cited examples from different utility industries including, on occasion, the railroads. For the most part, however, I have been concerned with the more nearly monopolized types of utility enterprise, and especially with the electric utilities, with whose problems I have had the most experience. It was my early intention to include a special chapter on that most frustrating of all current public utility problems—the regulation of natural-gas rates. But a tentative draft of such a chapter left me so dissatisfied that I have hopefully postponed publication pending further study.

I am indebted to so many public utility specialists for conferences and correspondence which have influenced the writing of these chapters that any attempt to express this debt here would be almost hopeless. But it gives me pleasure to thank particularly the following friends who have kindly read chapters in manuscript and who have given me the benefit of their suggestions and criticisms: Mr. John Alden Bliss, Mr. Gordon R. Corey, Professor James L. Dohr, Professor Robert Eisner, Mr. Franklin J. Leerburger, Mr. O. Townsend MacMillan, Mr. Hubert Nexon, Mr. Maurice R. Scharff, Professor William S. Vickrey, and Mr. Joseph L. Weiner. To Mr. Raymond J. Dixon, Editor of the Columbia University Press, I also express my keen appreciation for his expert and painstaking editorial work in the preparation of the manuscript for publication.

Finally, I owe a debt of gratitude to the Ford Foundation and to the Columbia University Council for Research in the Social Sciences for grants-in-aid that have permitted me to secure leaves from teaching duties—leaves without which the completion of this study would have been postponed indefinitely.

JAMES C. BONBRIGHT

Columbia University
October 10, 1960

CONTENTS

PART ONE

Basic Standards of Reasonable Rates

I

THE PUBLIC UTILITY CONCEPT

This is a study of the standards of reasonable or optimum prices applied, or proposed for application, to that limited but vitally important class of business enterprises called "public utilities." Since the relevant standards must depend in part on the special character of the enterprises under review, a foreword on this character is in order. But the foreword will be brief, since it is designed merely to supplement the more extensive discussions in the general treatises on public utility law and economics.

used in foreword

The term "public utility" is one of popular usage rather than of precise definition, and writers are not uniform in extending its scope to newer types of regulated enterprise, such as radio and television broadcasting.[1] For present purposes, however, the extension of the public utility concept need not concern us, since the basic principles of reasonable rates can best be developed by reference to the traditional public utilities—to those enterprises that have long been subject either to outright public ownership or else to government regulation of prices and of services. In the United States the control has usually taken the form of regulated private ownership, and this is the form that will be assumed throughout most of our discussion of price policy. It should not

[1] The American judicial opinions on the constitutionality of price-fixing statutes have used the phrase "business affected with a public interest" more frequently than the term "public utility" as a designation of a type of enterprise subject to special regulation. There has been a tendency to use the former phrase in a broader sense, restricting "public utility" to an enterprise enjoying special grants of authority and operating under an obligation to serve all applicants without "undue discrimination." Statutes sometimes apply special-purpose definitions, as does the Federal Public Utility Holding Company Act of 1935, which restricts the term "public utility company" to a company doing a gas or electric business. In Wall Street parlance, though not in law, the railroads are not classed as "public utilities."

be inferred, however, that an economic theory of public utility rates which is valid under private ownership becomes invalid under public ownership, and vice versa. On the contrary, the essential principles, as developed in these chapters, apply with modification under both forms of organization.

For the purpose of this study an enterprise is not regarded as a public utility unless the regulation to which it is subject includes direct control of its rates of charge for services. But governmental price control alone is not enough to confer public utility status upon an enterprise or an industry. By a generally, though not universally, accepted linguistic convention, there is the further requirement that the primary purpose of the regulation must be, ostensibly at least, the protection of the public in the role of consumers rather than in the role either of producers or of taxpayers.[2] For this reason if for no other, milk production was not converted into a public utility industry by the passage of state and Federal milk-price control laws; and the same statement applies to coal production under the former Guffey Act or to agriculture under the Federal farm-product price supports. To be sure, defenders of these price-support laws have often contended that they are really in the long-run interests of the consumers. But the defense comes from spokesmen for the producers.

Most public utilities can be divided conveniently into two major classes: (1) those enterprises which supply, directly or indirectly, continuous or repeated services through more or less permanent physical connections between the plant of the supplier and the premises of the consumer; and (2) the public transportation agencies. The most important members of the first class are the enterprises supplying electricity, gas, water, and telephone communication. The transportation agencies are sometimes divided into (1) the "steam" railroads along with competing forms of intercity public transportation, and (2) the local transit systems. Transportation, however, presents problems of unusual complexity and is therefore often reserved for special treatises that pay detailed attention, among other things, to the highly competitive nature of modern transport.[3] This book will cite illustrations of

[2] "Protection of consumers against exploitation at the hands of Natural-Gas companies was the primary aim of the Natural Gas Act." Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672, 683 (1954).

[3] One reason why transportation is so frequently treated as a separate subject

rate-making problems in the railroad or local transit fields. But the systematic development of principles will have primary reference to the nontransport utilities, and especially to the electric companies. The reason for this narrowed emphasis lies in the closer approach to monopoly enjoyed by these latter companies along with the telephone systems.

Despite the distinction just drawn between the transportation agencies and the nontransport utilities, even most of the latter utilities do a transportation business if we use "transportation" in a broad sense to include what are more frequently called "transmission" and (in gas and electricity parlance) "distribution." True, a local utility company may have a production or manufacturing department, as does an electric company which generates its own power or a gas company which manufactures its own gas. But the transmission-distribution phase of the business is a vital part of most public utility systems and may constitute the major component of the total cost of service. Moreover, even though the entire utility system is usually subject to regulation, it is likely to have derived its recognized utility status from the department of the operations concerned with the transfer of the gas, or the electricity, or the telephone messages from one location to another.[4] The economic significance of this fact will be noted in a later paragraph in this chapter.

"PRIVATE" BUSINESS VERSUS BUSINESS "AFFECTED WITH A PUBLIC INTEREST"

We have already in effect defined a public utility as any enterprise subject to regulation, including price regulation, of a type designed primarily to protect consumers. And in order to come still closer to traditional usage, we may amend the definition so

is that not all forms of transport fall within the public utility category. This statement applies obviously to the unregulated, private trucking business. But even the regulated carriers by road or water enjoy the use of public highways and waterways, the services of which are not sold on a compensatory basis.

[4] The more clearly entrenched public utility status of the transmission aspect of a regulated industry is illustrated by the pending controversy as to the extent and nature of jurisdiction by the Federal Power Commission over natural-gas production as distinct from pipeline transmission. In the field of electric power supply, companies producing power merely for sale at the bus bar have sometimes contended—I think, on occasion and in some jurisdictions, successfully—that their business was not subject to regulation by state public service commissions. In Great Britain, the first step toward the complete nationalization of the electric power industry was the nationalization of the main transmission system, the "grid."

as to make it apply only to those enterprises subject to regulation as a matter of long-run policy rather than as a temporary expedient in wartime or in some other emergency. But what are the special attributes of an enterprise, or of an industry of which the enterprise is a member, that give it "utility status" even in a country that has gone as far as has the United States in its reliance on the "automatic forces" of market competition for protection of consumer interests?

Down to the decade of the 1930s, the question just raised was often discussed as a legal problem—specifically, as a problem in constitutional law. Except in times of emergency, state and Federal legislatures were held by the Supreme Court of the United States to have no power to impose price restrictions on ordinary business enterprises. Statutes imposing such restrictions were held void as violations of constitutional guaranties of property rights, including the guaranties of the Fifth and Fourteenth Amendments. But exception was made of certain types of business said to have been "dedicated to a public use" or "affected with a public interest," and these types included the railroads and the familiar municipal utility companies. A layman might suppose that a list of all businesses affected with a public interest would be very long and that it would exclude only the producers of frivolous or luxury goods, which the community could very well do without. In fact, however, the early Supreme Court rulings were much more restrictive and did not go very far beyond the traditional public utility field in recognizing legislative power to fix prices or to impose upon private businesses restrictions not merely designed to protect "health, safety, and morals." [5]

Perhaps the most plausible way to rationalize these early legal cases, which seem to deny any public interest in the production of vitally important goods and services, is to infer that what the courts were denying was the public importance of any single producing firm or enterprise rather than the public importance of an entire industry. But this rationalization would not fit *all*

[5] For a review of the earlier judicial pronouncements on "business affected with a public interest," see "Rate Regulation," by Felix Frankfurter and Henry M. Hart, Jr., *Encyclopaedia of the Social Sciences*, Vol. XIII (New York, 1934). The article cites other literature on the subject, including Walton H. Hamilton's distinguished paper on "Affectation with Public Interest," 39 *Yale Law Journal* 1089–1112 (1929–30).

the cases; and it would be cogent only under the assumption of competition among many producers, no one of which has a sufficiently large share of the market to make its output or price-fixing policies a matter of general concern.

Today, however, any attempt to explain the early judicial distinctions between a public and private business has little more than historical interest, since the Supreme Court has now changed its own position, as indicated by the famous *Nebbia* case of 1934.[6] Legislative proposals to place a given industry under price regulation may now be considered on their merits from the standpoint of economic and social policy, and without serious danger of upset by reason of conflict with the older, traditional legal doctrines. But this does not solve the problem; it merely shifts the emphasis from considerations that have seemed of special importance to lawyers and judges to considerations that seem valid to persons unindoctrinated in legal lore.

ESSENTIAL NATURE OF THE SERVICE AND PUBLIC UTILITY STATUS

The preceding paragraphs have followed custom in defining a public utility as any enterprise actually subject to regulation as a public utility. But this definition begs a question that must now receive attention: why certain types of enterprise are, or should be, singled out for this treatment whereas others are free from direct price control and from related types of regulation except, perhaps, in a period of emergency such as a war. Modern writers generally agree that no simple or single answer will suffice. The economic and social forces that have imposed regulation, say, on the electric power companies are multiple and complex.

[6] Nebbia v. New York, 291 U.S. 502 (1934), upholding the constitutionality of a New York State statute creating a milk control board with power to set minimum and maximum retail prices. Speaking for the Court, Justice Roberts conceded that "the dairy industry is not, in the accepted sense of the phrase, a public utility." But he declared that the legislative power of price regulation is not limited to a public utility, and he also stated: "Many other decisions show that the private character of a business does not necessarily remove it from the realm of regulation of charges or prices. . . . The guaranty of due process demands only that the law shall not be unreasonable, arbitrary, or capricious, and that the means selected shall have a real and substantial relation to the object sought to be attained." Justice McReynolds wrote a vigorous dissent, concurred in by Justices Van Devanter, Sutherland, and Butler, in which he adhered to the older philosophy.

Moreover, they are not precisely the same as the forces that have imposed somewhat similar regulation, say, upon the interstate railroads.

Nevertheless, two attributes of a public utility business have received emphasis in the textbooks, and they will be discussed in turn. The first is the special public importance or necessity of the types of service supplied by utility enterprises; the second is the possession by utility plants of technical characteristics leading almost inevitably to monopoly or at least to ineffective forms of competition. As Clemens neatly puts it: "Necessity and monopoly are almost prerequisites of public utility status."[7]

As to the character of public utility services considered as a group, few persons would deny that they are essentials of modern living rather than mere luxuries or conveniences. A well-functioning transportation system, for example, is a matter of life-and-death importance to the nation. Especially in a large city, even a temporary stoppage of electric power service is serious, and a prolonged cessation would be disastrous. This recognized public importance of adequate utility service, available without delay at reasonable rates and without unjust discrimination, certainly helped to account for the public demand for regulation even in a period of American history which was notably unfriendly toward "government interference with business."

But what the recognized importance of public utility service fails to account for is the restriction of regulation to services which, however essential they may be to the life of a community or the whole nation, are no more so than are the supplies of many commodities and services produced and distributed by unregulated business. Granted that electric power and telephone service are necessities of modern living rather than mere luxuries,

[7] Eli W. Clemens, *Economics and Public Utilities* (New York, 1950), p. 25. Earlier writers sometimes stressed the special privileges usually accorded to public utilities as justifying special regulations—privileges including the power to take private property under the law of eminent domain and the right to use the public streets. But current writers, while conceding a relationship between possession of privilege and subjection to special duties, no longer view this relationship as one of cause and effect. Indeed, even in early years, the courts did not limit their list of "businesses affected with a public interest" to those businesses enjoying legal privileges denied to ordinary businessmen. See, e.g., Chief Justice Taft's opinion for the Court in Wolff Packing Co. v. Court of Industrial Relations of Kansas, 262 U.S. 522 (1923), distinguishing three classes of business "clothed with a public interest" justifying some public regulation.

so also are food, clothing, and housing. Yet the prices of these essential products are not subject to peacetime control of a public utility nature, with the partial exception of housing rentals in limited areas and under assumed conditions of abnormal scarcity. Indeed, if the supply of electric power is a necessity, so also must be the supply of the turbines, the generators, and the boilers needed for the production of this power. Yet the electric equipment companies are not treated as public utilities and are left as free to determine their own price policies as are other "private" industrial companies.

What must justify public utility regulation, then, is the necessity of the regulation and not merely the necessity of the product. Indeed, one may go further and note that modern public policy is far from satisfied with regulation limited to the protection of consumers in securing *essential* types and amounts of service at fair prices. Instead, it extends to the encouragement of abundant use of service, especially of electric service, stimulated by promotional rates that are nevertheless high enough to discourage wasteful consumption. The theory of public utility rate making would be a very limited and rather dull subject if it were merely a theory of the proper pricing of economic *necessities*.

What has just been said may seem so obvious as to be hardly worth mentioning. Indeed, I would not have stressed the point but for its bearing on the criteria of "reasonable" utility rates. One sometimes reads the contention that charges for public utility services should not be based on the ordinarily accepted standards of cost pricing, since these services are essentials of living and hence should be made freely available even to persons who cannot afford to pay the costs of production. What this contention ignores is the very weak correlation between necessities versus luxuries on the one hand and utility services versus non-utility products on the other. If the prices chargeable for all necessities were to be based on standards of ability to pay rather than on standards of cost pricing, then a reorganization of the country's entire price system would be in order.

The above-noted reference to essentiality of service as an earmark of a public utility should be distinguished from a related point of a more subtle character to be found in some of the literature, namely, the assertion that public utility services have a peculiarly *social* or *community* value, not reflected by the prices that individual consumers are willing to pay for them. This "social-value" theory will be discussed briefly at the end of this chapter and treated in more detail in Chapter VII. But whatever its merits, I feel sure that it has been of only secondary influence in the American and British development of public utility regulation.

NATURAL MONOPOLY AND PUBLIC UTILITY STATUS

It is the general consensus of economists that the primary, even though not the sole, distinguishing feature of a public utility enterprise is to be found in a technology of production and transmission which almost inevitably leads to a complete or partial monopoly of the market for the service. Public utility regulation, if chosen in preference to outright public ownership, is therefore said to be a substitute for competition. Whether or not it should be a closely imitative substitute is quite another question, and one reserved for discussion in Chapter VI.

This "natural-monopoly" theory of public utility regulation reflects an old and orthodox point of view. Properly qualified, I believe it to be sound. But it must be expressed today with more caution than would have been deemed necessary in earlier years. For, as modern economists have shown, the differences between a competitive industry in a realistic sense of competition and a monopoly, natural or unnatural, are far less sharp and less simple than was once assumed. Close approximations to "pure" or "perfect" competition are thought to be rarely if ever found in manufacturing or trading industries. On the other hand, even public utilities may face severe competition, typically of a substitute-product type,[8] with respect to a large fraction of their services—sometimes with respect to the major fraction.

It follows that the traditional distinction between monopolistic public utilities and competitive private enterprises is an oversimplification, since the true distinctions are those of degree rather than of kind. In attempting to draw such a distinction, moreover, one should not overlook the possibility that some important industrial companies have avoided regulation, not because they have been more competitive than most utilities but rather because of the recognized difficulties of an extension of effective regulation to the manufacture of commodities. Efficient regulation of the American steel industry, or even of the aluminum industry, would present far more serious problems than has regulation of the electric power utilities or of the telephone companies.[9] Reliance on a certain degree of competition, fortified by antitrust laws, may therefore be deemed the lesser evil.

[8] The term "monopolistic competition" has been applied to this type of competition: "monopolistic" because each firm has a monopoly of a significantly distinct type of commodity or service. See Edward Chamberlin, *The Theory of Monopolistic Competition,* 6th ed. (Cambridge, Mass., 1950).

ECONOMIES OF LARGE-SCALE PRODUCTION AND NATURAL MONOPOLY

The familiar statement that a public utility is a "natural monopoly" is meant to indicate that this type of business, by virtue of its inherent technical characteristics rather than by virtue of any legal restrictions or financial power, cannot be operated with efficiency and economy unless it enjoys a monopoly of its market. So great are the diseconomies of direct competition that, even if it gets an effective start, the competition will probably not long persist if only because it will lead to the bankruptcy of the rivals. But even if the competition is long lived, as has occasionally happened when the rivalry has taken a restrained form, it is wasteful of resources because it involves unnecessary duplication of tracks, of cables, of substations, etc.[10]

[9] Professor Wilcox makes the further point that public utilities deal directly with small consumers and hence are not faced so generally with the "countervailing power" that even large manufacturing companies face. Clair Wilcox, *Public Policies toward Business,* rev. ed. (Homewood, Ill., 1960), p. 541.

Note that in Great Britain, the Conservative Government, in 1954, denationalized the steel industry, which had been nationalized along with other activities by the previous, postwar Labor Government But it has not expressed any intent to denationalize electricity, gas, or railway transport. Arthur R. Burns, *Comparative Economic Organization* (New York, 1955), p. 245.

Few American economists, even among those who have insisted upon a serious decline of competition among the country's great industries, have looked for a solution to an "extension of the public utility concept." Instead, most of them have sought means of securing more effective, "workable competition." The dismal experiments with the N.R.A. Codes in the 1930s, which embodied some fair-price ideas akin to those of utility regulation, would be enough to give pause to further experiments in the same direction.

[10] With the electric power business in the United States and Canada, the most usual form of duplication within recent years has been that between publicly owned and privately owned electric plants. In some of the cities formerly receiving this duplicate service, such as Seattle, Wash., and Ottawa, Ont., rates were unusually low—a fact which might be cited as justifying a community in abandoning reliance

What then are the special characteristics of a public utility enterprise or plant which give it a natural monopoly character not conceded to other industries? An answer frequently given is that public utilities operate under conditions, or "under the law," of decreasing costs, whereas competitive enterprises operate under conditions either of constant cost or else of increasing cost. This means that the larger the output of a utility plant per day or per month or per year, the lower will be the cost of production and distribution per kilowatt hour, or per thousand cubic feet of gas, or per passenger mile, etc. Consequently, only a company enjoying a monopoly of the supply of service in a given area can operate at maximum economy.

This rationale of the natural monopoly status of the public utility industries was given currency, years ago, by the late Professor Henry C. Adams,[11] and has been repeated, with many variations, down to this day. Properly qualified, it remains valid. But a restatement is required. For, taken alone, the well-known economies of large-scale enterprise are by no means peculiar to the utility business. Instead, they are enjoyed by utilities in common with many unregulated types of enterprise, including steel companies, automobile companies, and chemical companies. Compared to some of the giant manufacturing companies and manufacturing plants, most utility systems are of a small-scale nature if measured by any of the conventional units of size.

What favors a monopoly status for a public utility is not the mere fact that, up to a certain point of size, it operates under conditions of decreasing unit cost—an attribute of every business, including a farm or a hand laundry. Nor is it even due to any indefinite extension of the declining-cost portion of a curve relating unit costs of production to scale of output. It is due, rather, to the severely localized and hence restricted markets for utility services—markets limited because of the necessarily close connection between the utility plant on the one hand and the consumers' premises on the other. As a deterrent to successful competition, this market restriction is far more serious than is the case with manufacturing companies which can ship their products throughout a wide region or even throughout the nation. An automobile plant may be large enough to enjoy the full economies of large scale without requiring more than a fraction of the American car market to sustain full-capacity output. But a gas distribution system in Yonkers, N.Y., or an electric distribution system in Evanston, Ill., has a market limited to the load of one city. Even if permitted to supply the entire load, the local distribution system will still be engaged in fairly small-scale business. Were it compelled to share its limited market with two or more rival plants owning duplicate distribution networks, the total cost of serving the city would be materially higher.

on rate regulation and in returning to public competition as a superior alternative. In view of the fact, however, that the public systems in Seattle, in Ottawa, and elsewhere have subsequently taken over the private systems and seem to have benefited by the resulting economies of a monopoly, these examples cannot be cited in support of direct competition.

[11] See Joseph Dorfman, ed., *Relations of the State to Industrial Action* (New York, 1954), which reprints two articles by Professor Adams. On p. 110 he is quoted as declaring: "The control of the State over industries should be co-extensive with the application of the law of increasing returns."

The reader may note that Yonkers is served by the gigantic Consolidated Edison Company, which also supplies gas and electricity to much of the area of New York City, and that Evanston is one of many cities served by the Commonwealth Edison Company, which also carries the entire Chicago electrical load. But growth in size through an extension of territory, while it may result in substantial economies of scale, is no adequate substitute for the opportunity of a utility to cultivate intensively whatever area it does serve.

What has just been said about the interplay of the factors of economies of scale and of localized markets points to the significance of the fact, already noted earlier in this chapter, that public utility companies are essentially transportation or transmission agencies. The technology of electric, gas, or telephonic transmission is such as to require a close connection between the plant on the one hand and the consumers' homes or factories on the other. This is even true, though less rigidly so, for a railroad plant. Not all forms of transportation are so strictly localized—not ocean shipping, for example, nor truck transport. But for this very reason, these two forms of transportation have a less well established utility status.[12]

[12] Compare the significance attached by a British economist to the fact that public utilities are suppliers of service, and not (or not simply) of commodities. J. F. Sleeman, *British Public Utilities* (London, 1953), Chap. 2. Along somewhat similar lines, H. S. Houthakker cites nontransferability and nonstorability of service as the two basic features of the market for electric supply which give it a special place from the point of view of price policy. "Electricity Tariffs in Theory and Practice," 61 *Economic Journal* 1–25 at 2 (1951).

ARE PUBLIC UTILITY SERVICES NECESSARILY PRODUCED AT DECREASING UNIT COSTS?

One further point about the monopoly attributes of a public utility should be emphasized in this chapter because of its important bearing on measures of desirable or "optimum" rates of charge. The point concerns the assumption, sometimes accepted by American writers as if it were axiomatic, that a public utility, by virtue of the very characteristics which put it into this category of enterprise, supplies service under conditions of decreasing unit cost with increasing rates of output. For example, a 50 per cent increase in the annual output of electric power (other things equal, including price levels, load factors, and number of customers) may result in an increase in total cost of only, say, 25 per cent. In consequence, the incremental cost of the service—the unit cost of supplying more of it—will be lower than the average cost. And this excess of average over incremental or marginal cost is thought to prevail, not merely as a short-run phenomenon when existing plant capacity is temporarily redundant, but even as a long-run or chronic phenomenon exemplifying the economies of large-scale output. The implications of this supposed cost differential for policies of rate making, which will be discussed at length in Part Three, will be apparent to anyone familiar with modern price theory.

Stated as a general tendency or typical situation applicable to most types of utilities in the United States in the present stage of their expansion, this assumption that a utility operates on the declining-cost portion of a long-run unit-cost curve may be valid, although the available data in support of any such generalization are rather sketchy because of the currently inadequate state of public utility cost analysis. But the point to be stressed here does not concern the question of general tendency or typical situation. It concerns rather what seems to be a widespread assumption that a public utility *must* be producing on the declining-cost segment of a unit-cost curve in order to justify its claim to acceptance as a natural monopoly. This assumption is quite unwarranted. It ignores the point that, even if the unit cost of supplying a given area with a given type of public utility service must increase with an enhanced rate of output, *any specified* required

rate of output can be supplied most economically by a single plant or single system.

By way of illustration, let us assume a region served by one electric utility which generates its own power in local plants. Three fourths of the generation is from economical hydroelectric plants at production costs (including capital charges on investment) of, say, ¼¢ per kilowatt hour. But since no additional water power is available within economical transmission distance, the remaining one fourth of the generation is by steam plants at a cost of, say, ¾¢ per kilowatt hour in an area of high fuel prices. Under these assumptions, the marginal or incremental cost of power generation will be ¾¢ per kilowatt hour, whereas the average cost is only 3¾ mills. In short, power is being produced under conditions of increasing unit cost. The increasing-cost behavior will be further emphasized if we also assume that, as more steam power is produced to meet the growing requirements of the area, even this power becomes more and more expensive to generate and transmit because of the absence of adequate condensing water or of good sites near the distribution network. To be sure, the increasing-cost tendency of the company's production department *may* be offset, or more than offset, by the declining-cost behavior of its distribution system. But there is no a priori ground for the assumption that the offset will be complete. Conceivably, the total kilowatt-hour costs of electric power in the area under review may rise as the rate of output increases, even assuming, as we do, no change in general price levels.

This hypothetical example of an electric utility company supplying power under conditions of increasing unit cost, irrespective of any change in price levels, may seem farfetched as an example applicable to this country today, although it may now apply to the Tennessee Valley Authority with its increasing reliance on steam power. But even when applicable, it does not belie the assumption that any given area can be supplied more economically by a public utility monopoly than by two or more companies operating in direct competition. For, on the one hand, the single company can secure the maximum advantages of economies of scale and of density, while on the other hand it is no more subject to the diseconomies of enhanced output resulting from scarcity of water power and of other natural resources than would two or more companies if called upon to supply the region with the same total output.[13]

The current literature on electric power rates in Great Britain and France reveals no such general tendency as one finds in the American literature to take for granted long-run trends of decreasing costs with increasing rates of output. In France available water-power resources have been pretty well exploited, and additional output must come largely from thermal plants. In England, where water power has always been of minor importance, emphasis has been placed on the increasing-cost character of coal supply and also on the difficulties of securing desirable sites and good condensing water for new power plants. (Hence the vigor with which the British government is now pushing the development of atomic-power plants.)

What the parallel situation may be in the future with electric power in this country is a question on which I venture no opinion, although the limited opportunities for further water-power development and even the scarcity of good condensing water (in some areas) are well recognized. It may be that, with expected further increases in demand for power, economies of scale can still more than offset limitations of sites and of raw materials. Moreover, the coming of atomic power may change the situation. But with natural gas, the increasing-cost tendencies of the production end of this wasting-asset industry threaten to outpace the economies of large-scale transmission and distribution. Whether or not the American railways, as a whole, reflect a type of industry still subject to long-run decreasing costs is a controversial question, to which a confident answer is precluded by lack of adequate data.[14] The telephone utilities, at least by their own contention

[13] In the economic textbooks, which usually discuss economies and diseconomies of scale under assumptions of competing firms, no one of which produces more than a small portion of the output of an entire industry, the above-noted distinction between simultaneously operative economies and diseconomies of scale can be expressed with less confusion. The diseconomies of the type illustrated by the scarce water-power resources are referred to as "external diseconomies"—i.e., as diseconomies external to any one firm in the industry; whereas the economies enjoyed by a monopolistic utility company through its ability to make use of larger generating equipment and of a more capacious distribution network are referred to as "internal economies"—economies internal to a given firm or company. But when a single firm enjoys a monopoly, the distinction between the firm and the whole industry disappears or, at least, becomes blurred.

[14] One must distinguish here between the question whether the railroads today, with their existing plant and equipment, are capable of handling additional

and under the usual assumptions of the textbooks, are subject to increasing unit costs if the telephone subscriber or station rather than the telephone call is taken as the unit of measurement. But, so far as I am aware, the telephone industry, despite its vast facilities for statistical and economic research, has never seen fit to publish elaborate studies of its cost functions; and until these studies have been made, a degree of skepticism is justified.[15] In any event, a telephone company does not present a standard example either of a firm or of an industry subject to "the law of increasing costs," since the character of the service rendered to any one subscriber changes significantly with a change in the number of other subscribers.[16]

COMPETITION OF SUBSTITUTE SERVICES AS AN ALTERNATIVE TO RATE REGULATION

This brief discussion of the reasons that account for rate regulation of public utility companies in nearly all countries which have adhered to private ownership should not ignore a minority position expressed in this country, some years ago, by a group of economists with a strong antipathy toward "government interference with business." While their views have won but little favor either among other economists or with the general public,

traffic at relatively low incremental costs, and the very different question whether railroads could enjoy further economies of scale even if they were not redundant with respect to the present, peacetime traffic. As to the first question, an affirmative answer is clearly indicated for American railroads as a whole. As to the latter question, my colleague Professor Vickrey has made studies on the basis of which he estimates that long-run marginal costs for freight transport on American railroads are materially below average costs—perhaps only 80 per cent of such costs. William S. Vickrey, "Some Implications of Marginal Cost Pricing for Public Utilities," 45 *American Economic Review, Proceedings* 605–620 at 614 (May, 1955). But he has necessarily relied on very inconclusive data.

[15] The telephone companies refer, quite persuasively, to the increasing-cost factor of their switching apparatus as the number of subscribers in each area increases. But there is a possible decreasing-cost offset in the cable and wire systems outside the telephone exchanges. There is the further question how the costs per station will respond to an increase in the number of stations in any given area, as distinct from an increase in the number of stations accompanying an extension of this area.

[16] Telephone company spokesmen insist that what they call "the value of the service" increases with an increase in the number of potential connections with other customers. This contention is more plausible for business users than for residential subscribers. I have heard several of these latter subscribers assert vigorously their wish that they could avoid being bothered with so many potential connections!

they are nevertheless entitled to careful attention as pointing to serious limitations of orthodox rate regulation.[17]

The contention of these economists has been that the assumed monopoly status of a public utility is an illusion, or at least a gross exaggeration. True, there seldom exists that primary form of competition illustrated by two electric companies vying with each other for the patronage of the same customers. But what does exist is the competition of substitute services or products. For many purposes, the use of electricity is alternative to the use of gas, oil, or coal. Moreover, the large industrial and commercial customer has a feasible option to produce his own electricity if the power company will not quote him a favorable rate. Similarly, communication by telephone must compete with possible communication by telegram, by post, or by direct contact.

Those writers who have stressed this point of view would concede that there are limited uses and amounts of a utility service for which the consumer may have no feasible substitute. This is notably true, for example, of electricity for lighting, where gas, even if available and even if provided by a rival utility company, must be dismissed as obsolete. But the contention is that the high potential profits from a modern utility business do not lie in a policy of high prices designed to exploit the most urgent uses of service. On the contrary, they lie in a policy of low "promotional" prices, of the type that will maximize profits by a

[17] The late Professor Philip Cabot of the Harvard Business School took the lead in presenting this point of view during the late 1920s and early 1930s. My incomplete references include: "Public Utility Rate Regulation," 7 *Harvard Business Review* 257–266, 413–422 (1929); "Ethics and Politics," *Atlantic Monthly*, Nov., 1929, pp. 686–694; "Four Fallacious Dogmas of Utility Regulation," 7 *Public Utilities Fortnightly* 719–729 (1931); "The Dangers of Rigid Rate Structures," 12 *Public Utilities Fortnightly* 183–191 (1933); "Rate Making and Rate Regulation," *American Bar Association Journal*, Oct. 11, 1932. For a similar point of view, see the testimony of the late President A. T. Hadley of Yale before the New York State Commission on the Revision of the Public Service Commissions Law, *Hearings*, Vol. II (1930), pp. 722–753.

The views of these economists, to the effect that utility rate regulation is both unnecessary and undesirable, bear a partial resemblance to the views expressed by those later writers who declare that rate regulation by public service commissions is ineffective because of its acceptance of a "static" cost-price standard of fair rates rather than a dynamic, competitive standard under which promotional rate reductions take the lead and under which unit-cost reductions result from increased rates of output. See, e.g., an address by Leland Olds, former Chairman of the Federal Power Commission: "The Economic Planning Function under Public Regulation," 48 *American Economic Review, Proceedings* 553–561 (May, 1958). But these latter writers insist on the need for "public yardstick" plants as a means of impelling private company managements to seek adequate profits by a policy of low pricing and of volume output.

heavy volume of sales. Thus, even the small user of electricity for lighting and for minor appliances will be protected, without government regulation, by the self-interest of a company in setting rates low enough to encourage bountiful consumption for uses less urgent or subject to feasible substitutes.

The writers who thus insist upon the competitive character of a modern utility business do not limit their objection to regulation to the claim that it is unnecessary. Instead, they have urged that it is positively harmful since it must result, at least in the long run, in utility rates higher than would prevail with unregulated private ownership. Regulation of the traditional type purports to restrict companies to a standard "fair rate of return" on invested capital or on property "values." Hence, it is believed to stifle the initiative and the risk taking inherent in an effort by management to maximize profits through cost reductions and through the promotion of heavy volumes of sales. If free to set its own rates, an intelligently managed, profit-seeking company will be led to make experimental rate reductions in the hope that, perhaps after a delay of one or more years, the resulting increase in the demand for the service may yield higher profits than ever. But if subject to regulation, the same company will hesitate to make a rate cut, since the anticipated increase in demand is far from a certainty, and since the company will not long be permitted to enjoy the benefit of the increase even if it should be realized. Moreover, under regulation in actual practice, a voluntary decrease in rates is not easily and quickly reversed even if the resulting rate of return should prove disappointing.

These are forcible arguments, if not against all feasible forms of regulation then against the more orthodox forms. They will be discussed again in Chapter XV, "The Fair Rate of Return." But the question now to be raised is why these arguments have failed to carry widespread conviction. A really adequate answer will not be attempted here, since it would involve a detailed review of the actual history of corporate rate-making policy in this country under the influence of different forms and degrees of regulation including, in some areas, the almost complete absence of regulation.[18] But two partial answers will be suggested.

[18] The extent to which regulation has actually restrained utility profits is largely a matter of surmise. A recent report by the Federal Power Commission enumerates six states in which there is still no commission regulation of electric rates, or only a limited form of regulation. *State Commission Jurisdiction and Regulation of*

The first answer is that, in actual experience, even those public utility managements that have been completely or relatively free from rate regulation of the "fair profit" type have not generally espoused a philosophy of low pricing designed to maximize long-run profits by the encouragement of widespread use of their services.[19] Instead, they have acted in much the same way as have the managements of the more rigidly regulated companies, by revealing a marked degree of skepticism as to the alleged price elasticity of the demand for their products. On occasion, to be sure, laxly regulated private companies have made drastic rate reductions on their own initiative rather than on order from a public service commission. But these reductions may be attributed to the example of adjacent publicly owned plants or to the fear of public-plant competition. The famous and oft-cited example of the late Henry Ford's dramatic cut in automobile prices, followed, rather than preceded, by a cut in production costs, has not found many imitators in the public utility field. One may perhaps add that it has not been widely imitated in other fields nor even often repeated in automobile production.

Of more interest for the theory of public utility rate making is a second reason why any proposal to rely on competition has failed to win more converts. The point is that public utility companies, if free from rate regulation, would seldom be under competitive necessity to make *general* rate reductions in harmony with opportunities of cost reduction. Instead, they would be more likely to follow the policy of rate discrimination, otherwise known as "charging what the traffic will bear," thus enjoying at one and the same time the commercial advantages of a high price policy with respect to services for which the demand is inelastic, and of a low price policy with respect to services for which the availability of substitutes makes the demand highly elastic.

For this practice of price discrimination the mechanism of

Electric and Gas Companies (Washington, D.C., 1954). But in some of these states city regulation is significant; while in some states with commissions having nominal power to regulate, actual regulation has been notoriously ineffective.

[19] This point of view was expressed by Commissioner Lewis Goldberg of the Massachusetts Department of Public Utilities in taking issue with President Hadley's denial of the need for strict rate regulation. New York State Commission on the Revision of the Public Service Commissions Law, Hearings, Vol. II (1930), pp. 815–817. The Commissioner stressed his belief that, in actual practice, public utility companies have based their rate-making policies on *short-run* profit objectives.

modern utility rate structures is admirably adapted. Through block rates, sometimes applied both to the "demand" charges and to the "energy" or "commodity" charges, favorable terms can be offered to large consumers who have a feasible option to generate their own electric power, while stiffer terms can be offered to small consumers. Still other devices of differentiation are available, such as special, low rates for services designed for special use. Not all of these differentials, to be sure, need be discriminatory in character. Indeed, all of them can be so administered as to conform to cost-of-service standards rather than to value-of-service standards. But an unregulated public utility is under no such limitation in the use of these instruments of monopoly power.

Let it not be supposed from the foregoing remarks that all forms and practices of rate discrimination are to be condemned as against the public interest. On the contrary, wise resort to discrimination of a value-of-the-service character is an essential tool of rate-making policy with respect to unsubsidized utilities that supply services at incremental costs lower than total average costs. But this very fact enhances the need for regulation. For it precludes the adoption of the proposal, sometimes made by persons who have not considered its logical consequences, to leave public utility companies the complete freedom to set their own rates subject only to a statutory mandate to avoid discrimination. Literally construed, the imposition of such a mandate would be fatal to private ownership. To be sure, even the traditional public utility laws are sometimes carelessly said to forbid discrimination. In fact, however, what they forbid is merely "undue" or "unjust" discrimination, thus placing upon commissions the major burden of interpreting and policing these ambiguous terms.

As already noted, the arguments against rate regulation have never won widespread support in their application to the so-called "municipal utilities" such as the electric power companies and the telephone companies. But arguments for much less restrictive standards of regulation have been receiving increasing attention and support with respect to the railroads. Largely because of the competition from the newer rival forms of transport, the railroads as a whole have been unable to earn rates of return that are adequate when measured by any of the conventional tests of adequacy. Even if completely free from rate control, only a few of them could expect to enjoy excessive rates of profit. Under these circumstances, and for the purpose of enabling them to compete more effectively with road, water, and air carriers, it has been proposed to amend the Interstate Commerce Act so as to permit them to set their own rates within a presumably wide band of minimum and maximum tolerable rates set by the Interstate Commerce Commission. Even within these limits, however, the Commission would still have the duty to enforce the rule against "unjust discrimination." [20]

The merits of this proposal will not be discussed in this monograph on public utility rates, since only a transportation specialist, with an intimate knowledge of the technicalities of the different forms of transport, including a knowledge of their cost functions, is competent to have an expert opinion on its merits. In its favor is the argument that substitute-service competition is more nearly all-pervasive for intercity transportation than it is for the local utilities. But if the proposal should be adopted by an act of Congress, one may guess that part of the trouble associated with the enforcement of reasonable rates under the current standards of the Interstate Commerce Commission would be transferred to the problem of redefining and reapplying the rules against "unjust discrimination." In any event, the need for some form of government regulation will remain.

PUBLIC UTILITY SERVICES VERSUS "SOCIALIZED" SERVICES

The emphasis placed by the legal and economic literature on the distinction between a public utility and an unregulated "private" business has unfortunately tended to obscure another aspect of "the public utility concept" that is quite as important from the standpoint of rate theory. The fact is that a public utility enterprise is nonetheless a "business" even though subject to

[20] This was a proposal of the controversial "Weeks Report": *Report of the Presidential Advisory Committee on Transport Policy and Organization*, April, 1955. Its recommendation on maximum-minimum rate control was designed to "limit regulatory authority of the Interstate Commerce Commission to determination of reasonable minimum or maximum rates with no change in existing provisions making undue discriminations and preferences unlawful." In Great Britain under railway nationalization, the freedom of the public corporation, called the British Transport Commission, in the fixation of railroad rates, has been made much more extensive, since the amended Transport Act seems to have gone far toward eliminating the old rule against "unjust discrimination." See Otto Kahn-Freund, *The Law of Carriage by Inland Transport*, 3d ed. (London, 1956).

regulation and even when directly owned and operated by the government. This statement, at least, is in accord with the spirit of the concept both in British and in American usage. Stated more concretely and without the many qualifications required for strict accuracy, public utility services are designed to be sold at cost, or at cost plus a fair profit.[21]

The thrust of this statement will be apparent if we compare the services supplied, say, by a municipally owned electric plant with other services supplied by the same city—for example, the construction and maintenance of streets and sidewalks. In all probability, the electricity will be sold at rates yielding a total revenue at least equal to cost including debt-service charges. Moreover, while the specific rate structure will not bear any very *close* relationship to the relative costs of different classes and amounts of service, a cost relationship will be present to an important degree. In short, the rates will be designed in accord with the old legal maxim, "Let the beneficiary bear the burden."

Not so with the city streets, nor with its parks, its zoological garden, its public schools, its health services, or its police system. These services are also costly to render, but the costs will be met directly or indirectly by taxation; and even the taxes will not be designed with any serious attempt at apportionment in relation to benefits received. The public schools, for example, are not only tuition free but are subject to compulsory attendance, and the payment of school taxes is not lightened for persons without children or for parents who choose to send their children to private schools. In short, the schools are not operated as a business, not even as a public utility business. They are "socialized" in a sense quite different from that which we have in mind if we refer to the "socialization" of an electric utility plant through municipal or state ownership. Only if a city, having taken over a private electric plant, were to abandon the effort to make it financially self-supporting in favor of free service, or of service

[21] "Within a more comprehensive legal framework, the public utility classification is designed on the one hand to distinguish industries best conducted as monopolies and on the other hand to assure that these industries will not, under normal conditions, look to government funds for support, but that they will be required to *sell* their services and look for support only to those who are the actual users." Martin G. Glaeser, *Public Utilities in American Capitalism* (New York, 1957), p. 8. Glaeser adds that city water supply presents a marginal case in which "the public utility classification limits the spread of a legal framework of collectivist economics."

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supplied on an ability-to-pay basis, would it have socialized the electric service as it has socialized schools and public hospitals. In that event the city's electric department would have ceased to be a public utility.

Having drawn this sharp distinction between a public utility service and a fully "socialized" service, we must of course hedge the distinction in a manner required of nearly all attempts to classify social institutions. On the one hand, even private utility companies and railroads are sometimes required or induced to violate "business" or "economic" principles by supplying free service to indigent people, or by operating trains that fail to cover even their out-of-pocket costs, or by adherence to rate schedules designed to deal gently with low-income consumers. On the other hand, services supplied directly by government run the whole gamut from those rendered completely without charge (public vaccination) to services rendered at high profits (a European tobacco monopoly). Moreover, linguistic convention applies the term "public utility" to a type of enterprise *traditionally* supplying service at cost or at cost plus a profit, even though the cost principle is violated in a given instance; for example, the New York City subway system, which has not even been covering its operating expenses to say nothing of interest costs on the invested capital.

Despite these qualifications, the distinction just drawn between a public utility service and a completely socialized service is basic to the prevailing theories of reasonable public utility rates. For, with important reservations, these theories are variations of the major theme that the consumers of public utility services (1) should be free to take whatever types and amounts of service they are ready to pay for but (2) in return therefor should be required to pay rates not seriously out of line with costs of rendition.

This book would be a very different work both in its development of rate theory and in its conclusions on wise public policy if the author did not accept, in the main and with important qualifications, the orthodox view that those services presently known as public utility services should be sold on a cost principle. But the reader should be warned that this view is not universally accepted. Among those who have apparently rejected it is Professor Horace M. Gray, whose article on "The Passing of the

Public Utility Concept" should be familiar to every student of public utilities.[22] Gray believed that the concept had become outmoded partly because of the failure of regulation to accomplish the very objectives which it purported to accomplish, namely, to serve as an effective substitute for competition. But he also insisted that a cost-price standard of rate making is inappropriate for application to electric power supply or to the other vital services now largely supplied by private enterprise on "business principles." [23] Social and national objectives, he believed, should supersede the limited objectives of a fair-profit or of a cost-price philosophy of rate making. At least, so I interpret his readiness to move away not only from private corporate ownership in its present form but also from the public utility concept as applied to a plant owned and operated directly by an agency of the government.[24] The merits of this "social theory" of price fixing, to which I would dissent except in special situations, will receive a brief discussion in Chapter VII.

[22] 16 *Journal of Land and Public Utility Economics* 8–20 (1940). Reprinted in *Readings in the Social Control of Industry* (Philadelphia, 1942), pp. 280–317.

[23] The reader should note carefully this twofold nature of Gray's devastating attack on the public utility concept in action. Gray himself fails at times to maintain a sharp distinction, since his article merges criticism number one (that regulation has failed to accomplish what it pretends to accomplish) with criticism number two (that even its pretense is shoddy). As to the first point, it was written with the lessons of the experience of the 1920s in mind, with their disgraceful episodes of holding-company finance and with a type of rate regulation seriously crippled by the Supreme Court's pronouncements on the "fair value" rule of rate making. But in 1935 came the Public Utility Holding Company Act and in 1944 came the Hope Natural Gas case, 320 U.S. 591, in which the Supreme Court accepted a very different, and less restrictive, philosophy of rate regulation. These and other developments associated with the "New Deal" helped to give a new lease of life to private ownership! But a recent book under Professor Gray's co-authorship indicates his continued hostility to regulated private monopoly and his support of limited degrees of competition even among utilities. Walter Adams and Horace M. Gray, *Monopoly in America* (New York, 1955), Chap. 3.

[24] How far Professor Gray would carry the departure from this concept under public ownership I am not able to say. Under Congressional mandate, the Tennessee Valley Authority, e.g., still adheres in the main to public utility principles as to its sale of power, though not as to its supply of navigation or flood control services. As to the nationalized British public utilities, Sleeman writes: "In general the commercial view of public utility undertakings still prevails strongly, and the 'social service' elements considered above are merely modifications on a predominantly commercial pattern." *British Public Utilities*, p. 278. To the same effect, see the *Report of the Committee of Inquiry into the Electricity Supply Industry Presented by the Minister of Fuel and Power to Parliament by Command of Her Majesty*, Jan., 1956, Cmd. 9672, p. 139: "We attach great importance therefore to the industry being run on business lines. It should have one duty and one duty alone: to supply electricity to those who will meet the costs of it and to do so at the lowest possible expenditure of resources consistent with the maintenance of employment standards at the level of the best private firms."

II

THE PUBLIC INTEREST AS THE ASSUMED GOAL OF RATE MAKING

The introductory chapter, on the public utility concept, has stressed the point that this concept itself carries with it important implications for rate-making policy. Thus, an assertion that the supply of telephone service or of electric power should be treated as a public utility implies that the service should be offered for sale instead of being given away and that the sale prices should bear a fairly definite relationship to cost, or to cost plus a fair return typically well below the point of monopoly profits. In other words, the so-called "theory of public utility rates" already starts with certain presumptions about the relevant principles of price determination.

We now turn directly to a study of these principles. But the principles cannot be derived from the public utility concept as a corollary is derived from a proposition in geometry. For in the first place, the concept is too indefinite; in the second place, it is sufficiently flexible to bring within its purview many divergent standards of reasonable rates; and in the third place, it admits of exceptions or deviations based on so-called "social considerations" of a type discussed in Chapter VII, "Social Principles of Rate Making." These possible exceptions are properly considered on their merits instead of being ruled out on the "jurisdictional" ground that their acceptance would violate the logic of the public utility philosophy.[1] Only if the "social considerations" are deemed so pervasive that they cease to be thought of as exceptions or deviations does the public utility concept become a handicap rather than a useful tool of economic thought, as Professor Horace M. Gray seems to have considered it in an article noted in the preceding chapter.

[1] The literature on public utilities, which includes its full share of efforts by class interests to practice the art of influencing people, has many examples of attempts to destroy the force of unwelcome proposals by an appeal to the inexorable logic of some basic social philosophy which the opponent may disavow at his peril. Thus, a project of public ownership, such as that of the Tennessee Valley Authority, is attacked as "creeping socialism." And thus the New York Natural Gas and Oil Resources Committee objects to Federal control of the prices charged by natural gas producers—because the control threatens the producers' opportunities to make money? Oh, no! Because "the proposed controls are against the public interests and *can benefit no one*" (*original italics*). "The issue," continues the committee, "goes far beyond gas. It goes to the roots of America's greatness." Advertisement in the New York *Times*, March 16, 1955, p. 36.

PUBLIC-INTEREST OR SOCIAL-WELFARE CRITERIA OF REASONABLE RATES

As used in this book and in most of the treatises on public utility economics, "the theory of rates" is a normative, not a positive, study. Its task is the systematic development of principles of rate-making policy, the complete or qualified observance of which would subserve "the public interest" or "the social welfare." In its acceptance of a norm or goal by which to appraise the relative merits of alternative rates, it is in the same class with other purposive theories, such as a theory which defines optimum rates as whatever rates will maximize corporate profits, or such as would be a theory of electric rates designed to minimize the charges for service supplied to residential customers. But it is almost unique in the extreme vagueness of its ultimate verbal norm and in the highly indirect and unprovable relationship between changes in utility rate-making policies and effects on social welfare, however defined.[2] Indeed, one is tempted to say that the so called standard of public interest is not a real standard at all; that, instead, it is a mere form of words of highly emotional

[2] But even a maximum-profit standard of rate-making policy is by no means free from ambiguities. It can be cleared of these ambiguities only by factitious definitions of "profits" and of applicable maxima that would convert it into a standard which no corporate management would be interested in following. The ambiguity applies notably, though by no means solely, to the assumed standard of maximum "long-run" profits. In the words of Professor Joel Dean, an expert on the pricing policies of unregulated, industrial enterprises, the modern economist's conception of profit maximization as a practical objective of private enterprise "has become so general and so hazy that it seems to encompass most of man's aims in life." *Managerial Economics* (New York, 1951), p. 28.

content, invoked as an instrument of persuasion by people who have at heart much more immediate interests in public utility tariffs—interests often, but not always, of a self-seeking nature.

At least as applied to prevailing conceptions of public interest or social welfare in this country at the present time, such a belittling statement would go too far.[3] But it has sufficient validity to suggest the formidable problem faced by any economist or rate specialist who undertakes to appraise alternative proposed measures of reasonable rates from a public-interest standpoint—the problem of developing less indefinite, less controversial, and more nearly objective goals of rate making that nevertheless make sense when viewed as instruments of sound public policy.

This serious handicap imposed upon any social-welfare theory of public utility rates by the indefinite nature of its assignment might be supposed to doom it at the outset to complete failure. Indeed, some such conclusion may be implied by those rate experts who reject *any* "theory" on the ground that "rate making is an art, not a science." But the situation is not quite as frustrating as it might seem. Indeed, it is not as serious as that presented by other and grander issues of wise economic policy, such as issues of socialism versus capitalism. The reasons for this hopeful conclusion are fairly obvious, but they may nevertheless be worth a brief summary.

[3] Ostensibly, at least, most of the disputes about public utility rate-making policies that come before legislatures, courts, and regulating commissions in this country involve no basic disagreements about "ultimate human values" or even about the proper economic organization of society. Instead, they appear to involve, for the most part, controversies about means to the attainment of ends that all disputants would concede to be desirable. To this extent, they would support the views of the late Professor Henry C. Simons and of Professor Milton Friedman, to the effect that, in America today, there is general agreement on the larger objectives of economic policy and that the real issues have to do with means, not with ends. Henry C. Simons, *Economic Policy for a Free Society* (Chicago, 1948), p. 40; Milton Friedman, *Essays in Positive Economics* (Chicago, 1953), pp. 4–7.

But in its application to public utility problems, the statement that controversies are confined mainly to means rather than to ends requires two important qualifications. The first is the obvious one that most of these controversies involve a clash of individual or class interests such as that between corporate stockholders who seek higher dividends and residential consumers who seek lower domestic rates. Each side invokes public interest issues as weapons to throw at the enemy. The real objectives of the disputants are, in a sense, directly opposed to each other, although in another sense they are the same (or are "symmetrical") in that each side is out for itself, as in a football game. The second qualification, suggested by the social philosophy of John Dewey, is that we live in a means-ends continuum, not in a world which neatly divides goals of action into instrumental goals and ultimate ends. This point of view, unfortunately too seldom recognized in standard economic theory, is implicit throughout the following pages.

In the first place, public utility economics may usefully accept as "given" those basic conceptions of social welfare that prevail in the country and in the time period under review. At least in Western Europe and in the United States, this would mean, among other things, the identification of the public interest with the welfare of the people in the community or nation, the state being regarded merely as an instrument for the attainment of this welfare.

In the second place, and related to the first point, the public utility economist is justified in going a long way toward the acceptance, as final for his restricted assignment, of widely held goals of economic policy that a social scientist or social philosopher might properly regard as subjects for intensive and critical analysis. A vitally important example of such a goal is that of "consumer sovereignty," under which the allocation of the community's scarce resources is made to depend on consumer choices or preferences rather than on governmentally determined decisions as to relative needs or national interests. This goal is basic to the whole modern theory of public utility prices and forms the underlying rationale of a cost-price standard of utility rates. But it is no more fundamental to the theory of utility rates than to the theory of economic organization in general. Hence the author even of a large treatise on public utility economics is under no obligation to present either an elaborate defense or an elaborate critique of the standard. Instead, he is justified in limiting his inquiry to the question whether and to what extent the *special character* of public utility services calls for departures from the basic standard of consumer sovereignty in favor of rates designed to attain social objectives (say, national defense) that may not be attained if the service is offered for sale at cost of production.

In the third place, public utility rate theory has a great advantage over broader theories of sound economic policy because its interest is limited to those highly restricted goals effectively attained by programs of rate control. By and large, the task of rate making or rate regulation is that of adapting utility rates to a larger economic environment, including a universe of non-utility prices and wages, on which these rates have only a limited

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repercussion. This means that the role of public utility rates is severely limited, though by no means completely predetermined, by the country's general price and wage system. To be sure, any grandiose scheme for the economic reorganization of society would include changes in the pricing of services now classified as public utilities. Indeed, a socialist, concerned to carry the country over gradually to the wholesale nationalization of industry, might well begin with a program for subsidized, publicly owned, utility systems. But the rate-making policies involved in such a program would be policies of socialist strategy; they would not be principles of public utility rate theory in the accepted sense of that term.

The opportunity, enjoyed by public utility theory, to cut down social-welfare issues to more nearly manageable size by keeping within the restrictive bounds of its subject matter will be discussed at length in the next chapter, on the role of utility rates, as well as in Chapter VIII, on social theories of rate making. But one possible example of such an opportunity may serve here as an illustration. It concerns the question whether or not public utility rates, like income taxation, should be based on the relative abilities of rich and poor consumers to pay for the service, thereby serving partly to offset inequalities in personal cash incomes. If, in answering this question, the public utility specialist were under obligation to pass judgment on the whole public policy of programs of social control looking toward reduction of personal-income differentials, he would be carried hopelessly out of his field into a controversial area in which he has no special competence and about which he could probably say nothing not already said more ably and succinctly by other writers. Yet, in appraising the merits of "ability-to-pay" criteria of reasonable utility rates, he is not completely silenced by a lack of professional competence in income-distributive philosophy in general. A significant answer to the question just raised—admittedly not conclusive in all situations, yet persuasive for general rate-making policy—is that public utility rates are ineffective instruments by which to minimize inequalities in income distribution and that alternative instruments (including public education, social security laws, progressive taxation, and possibly even some form of socialized medicine) are better designed to accomplish this objective even on the assumption that the objective itself is desirable. Reasons for this conclusion are suggested in Chapter VII.

ASSERTED RESTRICTION OF PUBLIC UTILITY RATE THEORY TO "ECONOMIC" PRINCIPLES

Writers on general principles of public utility rates naturally welcome feasible opportunities to simplify their assignment by limiting attention to those objectives of rate-making policy, the attainment of which can be aided by fairly definite standards of optimum or reasonable rates. Thus, a study of rate theory may ignore, or dismiss with brief comments, political considerations, special statutory provisions, and important technical details or special situations that call for close consideration by persons engaged in the actual practice of rate making or rate regulation. These "practical" or legal issues do not lend themselves to useful generalizations. Moreover, they can be discussed more intelligently by actual practitioners than by those professional economists on whom has fallen the major responsibility for the development of general rate theory.

But what must now be noted is the assertion, frequently found in the literature of rate theory, that this theory is concerned solely with *economic* principles of rate making, or solely with considerations of *economic welfare.* The significance of such statements requires notice in this chapter, since they raise the puzzling question how *any* public utility rates or rate-making policies could have an effect on individual or social welfare other than an *economic* effect.

In the current publications on rate theory by academic economists, the most frequent use made of this self-imposed restriction to "economic" principles is to absolve the economist from any professional concern for considerations of *fairness* or *equity* as between investors and consumers, or as among different classes of consumers. Instead, the merits of alternative rules of rate making are to be judged solely by reference to their functional efficiency in getting the work of the world accomplished—in attracting capital to public utility enterprises, in supplying incentives to high-grade management, in controlling the demand for the service, etc. Thus, a recent monograph by an academic economist on public utility rate discrimination, in its discussion of the controversial problem of capacity-cost allocation, declares that it will analyze the problem solely "from an economic point of view. Whether or not the various methods proposed could give results that are 'just' or 'equitable' will not be discussed." They are omitted, presumably, because they raise ethical questions, as to which an economist has no professional competence.[4]

A different distinction between "economic" and "noneconomic" considerations of rate-making policy has been expressed or implied by other writers including, especially, those from the engineering professions. Here, "economic" principles of rate making are contrasted with "social" principles or social objectives. For example, rates of charge for electric service that fail to cover the out-of-pocket cost of supplying small consumers may be called "economically unsound" even by a writer who concedes that they may nevertheless be "socially desirable." Or again, a policy of transportation rate control that may result in driving a high-cost transportation agency out of business (perhaps the road hauler, or perhaps a branch railroad), while declared sound if judged solely by "economic" criteria, may nevertheless be opposed for ("noneconomic") reasons of national defense.

The above-noted distinctions between so-called "economic" and "noneconomic" standards of rate making will be discussed in later chapters, especially in Chapters VII and VIII. But one may question the accuracy, without denying the convenience, of the use of the adjective "economic" as the term by which to characterize the distinctions. For even a national-defense principle or an ability-to-pay principle of rate-making policy is an "economic principle" according to the most widely accepted modern definition of economics as "the study of the principles governing the allocation of scarce means among competing ends."[5]

I confess my own inability to find any consistency in the various distinctions that writers, including myself on occasion, have

[4] Ralph Kirby Davidson, *Price Discrimination in Selling Gas and Electricity* (Baltimore, 1955), p. 111.

[5] In thus defining economics, Professor George J. Stigler adds the proviso that the objective of the allocation of the scarce means must be "to maximize the attainment of the ends." *The Theory of Price*, 1st ed. (New York, 1946), p. 12. This proviso might possibly be held to exclude the objective of fairness as an "economic" objective. But it could hardly exclude national defense or other so-called social objectives such as income redistribution or decentralization of population.

drawn between "economic" and "noneconomic" principles of public utility rates. "Economic" is perhaps best regarded as a term of convenience, the import of which must be derived from the context, as in a statement contrasting "economic" principles of rate making with "legal" principles. But the closest approach to consistency seems to me to lie in the use of the term "economic" to denote whatever general principles of rate making have been developed or systematized by professional economists, and defended by them as valid under simplified but useful assumptions both as to the fact situation and as to the normal role of utility rates.[6]

"REASONABLE" RATES VERSUS "OPTIMUM" RATES

It is a general doctrine of American law, almost universal in its application to public utility companies operating under special franchises or "certificates of convenience and necessity," that these companies are under a duty to offer adequate service at "reasonable" (or "just and reasonable") rates. In addition, the governing state or Federal statutes require that, in its rates of charge as well as in its supply of services, a company must avoid "unjust" or "undue" discriminations or preferences among consumers. But the rule against undue discrimination is a mere extension of the mandate of reasonable pricing to reasonable price relationships, and it need not be distinguished for present purposes.[7]

[6] Compare I. M. D. Little's contention that the phrase "economic welfare" involves a misplacement of the adjective. The proper distinction, he insists, is between economic and noneconomic means of attaining human welfare. *A Critique of Welfare Economics* (Oxford, 1950), p. 6.

[7] See Chap. XIX. While some of the public utility statutes rest content with the requirement that rates be reasonable and not unjustly discriminatory, others go a certain distance toward prescribing or implying standards of reasonableness. The prescriptions may take the form of an enumeration of objectives of rate-control policy, as in the various amendments to the Interstate Commerce Act. Or they may take the form of a partial enunciation of measures or tests of reasonable rates which the regulating commission is instructed to follow or which it must "take into consideration" in reaching a rate decision. All of these statutory provisions leave much room for "interpretation" by a commission, subject to the rulings of the appellate courts.

In a brilliant article on "Commissions, Rates, and Policies," 53 *Harvard Law Review* 1103–1144 (1940), Professor Robert L. Hale comments on opinions of the Supreme Court restricting the standards of lawful rates under the Interstate Commerce Act to "transportation standards." United States v. Illinois Central R. R., 263 U.S. 515, 525 (1924); Texas & Pacific Ry. v. U.S., 289 U.S. 627, 637–638 (1933). In

In many of the pages throughout this book, we shall have occasion to compare the criteria of reasonable rates established by statutes, courts, and commissions with those rate-making principles that have had the support of economists. But what calls for present comment is the distinction between the traditional legal standard of *reasonable* rates or rate relationships, and the standard of "*optimum*" rates often set forth as the ideal of public utility rate theory. The law accepts results that are merely *satisfactory,* whereas economic theory seeks the conditions for the attainment of the ideal.

A full treatment of the import of the legal rule of "reasonableness" as applied to utility rates would go far beyond the scope of this study. But certain aspects of the subject are fairly elementary. In the first place, the law of public utility rates is, for the most part, a law of rate *regulation*. Instead of prescribing a complete set of principles or measures of rates, it leaves primary responsibility for rate-making policies to the management of the enterprise, private or public, so long as the management keeps within bounds set by public-interest or consumer-interest considerations. Only rarely will a commission feel called upon to take the initiative in dictating the precise rates that a company must charge. Its usual action is that of deciding whether or not existing or proposed rate schedules are reasonable or unreasonable.[8]

[redacted]declared: "The Act was passed for the protection of those who bear the rates. The standards it establishes are transportation standards, not criteria of general welfare." The term "transportation standards" was, and continues to be, ambiguous. But the statement that the Act was designed to serve limited purposes and not to accomplish unlimited objectives of public welfare is quite in keeping with the position of economists as to the limited functions properly assigned to public utility rates as instruments of social control.

[8] As a matter of practice rather than of legal authority, state public service commissions have tended to allow private companies much more freedom in determining rate structure or rate design than in determining the general level of their rates.

Under the Interstate Commerce Act and some of the state utility statutes, courts and commissions have thought in terms of a zone of reasonableness, within which zone existing rates may not be disturbed by commission fiat (barring a finding of unjust discrimination). But if the commission finds, "as a judicial fact," that existing rates lie outside this zone, it may, if it so chooses, set the precise new rates instead of directing the company to propose reasonable alternatives. See Robert L. Hale, "Commissions, Rates, and Policies," cited in the preceding footnote. For a general treatment of the concept of a zone of reasonableness under the Interstate Commerce Act, see I. Leo Sharfman, *The Interstate Commerce Commission,* Vol. III B (New York, 1936), pp. 417-421, 425-428, 652. Unlike this act,

But even if the scope of rate regulation were not so limited and even if the whole task of rate making were to fall upon regulating commissions, these commissions could not possibly hope to discover that particular rate structure, or even that particular complex of rate-making criteria, which is better than any other when judged by any plausible tests of goodness. *Satisfactory* results, not ideal or optimum results, are all that can be expected of the ablest group of rate makers.

Unlike actual practitioners of rate making, the rate theorist seldom has the task of putting his theory into practice. Any attempts on his part to set up principles of optimum rates are therefore mere attempts to state conditions, the attainment of which *would* result in the best rates *if* the fact situation and the objectives of rate making were those which he postulates. But even the economist, if he wishes to get beyond highly artificial, simplified assumptions as to the role of utility rates, so as to participate with the practical rate experts in developing *workable* standards of rate design, will be compelled to abandon the goal of optimum rates in favor of less lofty and less precise standards of adequate performance. Like the courts or the public service commissions, the economist must then rest content with principles of *reasonable* rates, although his standards of reasonableness may differ materially from those accepted by the law or by popular opinion.[9]

RATES AND EFFICIENT PERFORMANCE OF FUNCTIONS

The reasonableness of any public utility rates should be determined primarily by standards of efficient performance of their accepted functions. The reader may well regard this statement as a mere truism. Yet, truism or not, it emphasizes an approach to rate-making problems not always reflected in the legal cases or in popular controversies. It implies that any rule of rate making, such as a rule that rates should be based on average cost, or on marginal cost, or on "value of the service" instead of cost, must be adjudged good or bad, reasonable or unreasonable, primarily by reference to its effectiveness in securing rates that will per-

the Natural Gas Act of 1938 authorizes the Federal Power Commission to order a reduction in rates to "the lowest reasonable rates."

[9] For a discussion of important differences in emphasis, see Chap. VIII.

form the proper functions of a price system when applied to public utility services. What these proper functions may be with respect to any given type of utility enterprise is a controversial question, for reasons to be discussed in the next chapter. But the controversy merely adds to the difficulty of a functional approach to rate theory without offering any rational alternative.

A striking illustration of the difference between a functional and a nonfunctional appraisal of rate-making policy may be found in a comparison between the earlier opinions of the Supreme Court upholding the "fair value" rule of rate making as a mandate of constitutional law, and the later opinions of the Court in rate cases beginning with, or shortly before, the *Hope Natural Gas* decision in 1944.[10] True, even the old "fair value" rule lends itself to an interpretation under which a plausible, even if not convincing, case can be made in its favor on functional grounds—on grounds of the efficiency of the rule, when properly applied, in enabling a company to attract capital during a period of price inflation.[11] But it was not so interpreted and so defended by the Supreme Court in the days when it was held to reflect the constitutional "law of the land." On the contrary, it was rationalized as an application of the general guaranties of property rights established by the Fifth and Fourteenth Amendments to the Constitution of the United States. Whether or not it was feasible of administration, or efficient as a means of enabling a corporation to attract needed capital, or conducive to managerial efficiency, or otherwise effective as a means by which to harness the profit-making objectives of private investors to the job of supplying the nation or the community with railroad and public utility services, were questions which, if deemed relevant at all, were not recognized as the controlling issues in the ruling opinions.[12]

[10] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944). See also Chief Justice Stone's ruling opinion in the preceding rate case, Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575 (1942).

[11] See Chap. XIV.

[12] Compare the following critical comment on the nonfunctional approach to rate regulation believed to have been current at least as late as 1938: "The entire machinery of present-day rate fixing bears little relation to the frequently-asserted purpose of regulation to provide maximum service at minimum costs. If, instead of attempting at great expenditure of time and money to ascertain what a utility is 'entitled to earn' (legalistically speaking), the accent were to be placed on the company's reasonable and essential needs, or 'costs,' including those of required capital, regulation would apparently be on its way toward a direct approach to this basic aim." *Final Report of the Telephone Rate and Research Department*, Federal Communications Commission, June 15, 1938, mimeographed, p. 23. Prepared under the direction of Carl I. Wheat.

The early failure of the Supreme Court to appraise the merits of its fair-value rule and its other rules of rate control by reference to their practical efficiency may be explained in part on the ground that these early rules were designed, not directly as tests of reasonable rates but rather as setting limits below which commission-imposed or statutory rates would be held to be so outrageously low as to amount to "confiscation" of private property. In actual practice, however, "reasonable" and barely "nonconfiscatory" rates became seriously blurred. See my *Valuation of Property* (New York, 1937), Chap. 30.

A very different point of view is reflected by the written opinions of the justices in the *Hope* case, including both the concurring and the dissenting opinions. Justice Douglas, speaking for the Court in sustaining the rate order of the Federal Power Commission, threw major emphasis on evidence tending to show that the prescribed rates were adequate to maintain sound corporate credit. In short, he stressed the capital-attraction function of utility rates. Justice Jackson wrote a dissent. But the dissent itself was a brilliant example of another functional approach to rate theory. It stressed the exhaustible character of natural gas as justifying special price policies designed to conserve a limited natural resource for its more important uses. In short, Justice Jackson emphasized a conservation function of utility rates—a special form of the so-called "resource-allocation function" to be discussed in the next chapter.

The following chapter, on the role of public utility rates, will develop further the thesis that the basic standards of reasonable rates should be primarily standards of functional efficiency. But just as the acceptability of a headache tablet must be determined in part by reference to its undesired side effects and not alone by reference to its effectiveness as an anodyne, so also must the reasonableness of any given rates or rate policy be determined in part by reference to its unintended consequences. The administration of *any* standard or system of rate making has consequences, some of which are costly or otherwise harmful; and these consequences may warrant the rejection of one system in favor of some other system admittedly less efficient in the performance of its recognized economic functions. Thus an elaborate structure of rates designed to make scientific allowance for the relative costs of different kinds of service may possibly be rejected in favor of a simpler structure more readily understood by consumers and less expensive to administer. And thus a system of rate regulation that would come closest to assuring a company of its continued ability to earn a capital-attracting rate of return may be rejected in favor of an alternative system that runs less danger of removing incentives to managerial efficiency. The art of rate making is an art of wise compromise.

STANDARDS OF REASONABLE RATES INVOLVE REASONABLE RESOLUTIONS OF CONFLICTS OF INTEREST

In the preceding paragraph, a crude analogy was drawn between the problem of developing standards of reasonable public utility rates and the problem of developing standards of acceptable commodities, such as headache tablets. The rates, like the tablets, must be adjudged reasonable or unreasonable, satisfactory or unsatisfactory (in the light of available alternatives), not only by reference to their effectiveness in the performance of their intended functions but also by reference to the minimization of undesired side effects.

But the determination of reasonable rates introduces one complication not ordinarily involved in standards for satisfactory commodities, such as headache tablets or automobiles. By and large, standards for these commodities are those of satisfaction to the person who swallows the pill or who buys the car. But principles of reasonable rates are designed partly to resolve conflicts of interest among different parties, particularly between investors to whom a rate means a source of income and consumers to whom it means an item of expense.

This interest-conflict aspect of rate making is emphasized in the legal cases, which tend to associate, if not completely to identify, rates that are "reasonable" with rates that are *fair* or *equitable* as between buyers and sellers, and as among different classes of buyers. As will be noted in Chapter VIII, on fairness criteria (when distinguished from functional-efficiency criteria), it raises problems that defy scientific solution unless one accepts as "given" the standards of fairness prevailing in the community; and not even completely then because these standards are themselves in conflict with one another.

But while interest conflicts present serious difficulties, their

rational solution is not as hopeless as one might assume at first thought. For in the first place, notions of fairness, such as those based on good-faith performance of earlier promises, are themselves partly utilitarian. In the second place, some of the most important principles of rate making, such as those designed to secure an optimum allocation of the country's scarce resources as between the production of utility services and the production of alternative goods or services, are related only indirectly to conflicts of interest among different individuals. And in the third place, under systems of private or public ownership that depend entirely on revenues rather than on taxes for financial support, there is an important degree of harmony between the interests of consumers and of investors. This partial harmony justifies a public service commission in going far toward the acceptance of the long-run interests of consumers as its sole responsibility. With an important qualification,[13] the legitimate interests of investors may be regarded as amply protected by the allowance of rates sufficiently high to maintain corporate credit and hence to assure the maintenance of adequate service.

THE PUBLIC INTEREST AND "WELFARE ECONOMICS"

No chapter on "the public interest" or on "maximum social welfare" as the ultimate objective of rate-making policy can afford completely to ignore a restricted conception of economic welfare developed by that modern branch of economics called "theoretical welfare economics" or (quite illegitimately) simply "welfare economics." [14] In line with Western European tradition, this school of thought identifies the welfare of any given community with the totality of the welfares of the individuals therein. Also in line with this tradition, it accepts the revealed choices or

[13] The "important qualification" lies in the possible obligation of commissions to protect the interests of investors who may have committed their funds in reliance on rules of rate making no longer accepted. See pp. 155–158.

[14] For an introduction to the significance and principles of modern theoretical welfare economics, see Melvin W. Reder, *Studies in the Theory of Welfare Economics* (New York, 1947); Kenneth Boulding, article on "Welfare Economics," in Bernard F. Haley, ed., *A Survey of Contemporary Economics*, Vol. II (Homewood, Ill., 1952); I. M. D. Little, *A Critique of Welfare Economics* (Oxford, 1950); J. de V. Graaff, *Theoretical Welfare Economics* (Cambridge, England, 1957). See also the references on marginal-cost pricing in Chap. XX. The great classic on welfare economics in a broader sense is A. C. Pigou, *The Economics of Welfare*, 4th ed. (London, 1932). But Pigou does not refrain from making interpersonal comparisons.

preferences of individuals as determining the relative satisfactions derivable by these individuals from alternative forms of action. This acceptance of the preferred position as the position more conducive to individual welfare is what gave specious support to the contention, now no longer advanced, that welfare economics can pass judgment on economic welfare without taking any position on ethical values.

Up to this point there is nothing esoteric in the welfare economist's conception of economic welfare. What is esoteric, however, is his denial of any scientific basis by which one may make interpersonal welfare comparisons—by which one may decide whether an economic change which adds to the welfare of some individuals while detracting from the welfare of others will enhance or diminish net social welfare. This self-denial limits the welfare economist (of the more rigorous persuasion) to attempts to pass judgment on the welfare implications of those proposed changes in economic policy which, while benefiting some members of the community, will not be adverse to any other members. Needless to say, such a limitation is a serious impediment to the resolution of controversies in the field of public utility rate making, since most of these controversies present a clash of interests among the parties to the dispute. And only to a minor extent is the impediment removed by the qualification, now generally accepted in welfare economics, that any proposed economic change will contribute to total economic welfare if the individual beneficiaries, after being actually made to indemnify all the individual losers, will still remain net beneficiaries.

For the reason just suggested, as well as because of the variety of oversimplified assumptions on which reliance must be placed to prove the validity of propositions as to what action will tend to enhance economic welfare, theoretical welfare economics has only a limited usefulness to persons concerned with practical problems of rate making or rate regulation. But "limited usefulness" by no means implies trivial usefulness. On the contrary, a study of the norms of "optimum pricing" set forth by modern welfare economists should help materially in the development of practical principles of rate making. This statement applies notably to the analysis of marginal-cost pricing in the American and

European literature of welfare economics—a subject to be discussed in Chapter XX.[15]

With this brief introduction to the problem of developing social-welfare or public-interest principles of utility rates, we now turn to the role that these rates are designed to play as instruments of economic control.

[15] But compare J. Wiseman, "The Theory of Public Utility Price—An Empty Box," 9 *N.S. Oxford Economic Papers* 56–74 (1957).

III

THE ROLE OF PUBLIC UTILITY RATES

The previous chapter, on the problem faced by rate theory in developing social-welfare criteria of reasonable rates, has emphasized the importance of a functional approach. That is to say, the merits of any established or proposed principles of rate making must be appraised primarily by reference to the estimated effectiveness of the resulting rate schedules in performing the functions properly assigned to utility prices as instruments of economic control. What, then, are these functions? Two possible functions (a capital-attraction function and a use-rationing function) were mentioned casually as illustrating the functional approach to the law of public utility rates taken by Justices Douglas and Jackson in their opinions in the *Hope Natural Gas* case.[1] But the subject now requires a systematic treatment—all the more so since it receives only incidental attention in the standard treatises.

A partial explanation of the tendency of the literature to deal only incidentally with the role of public utility rates may lie in a widespread assumption that this role is fairly obvious and that the only really tough problems lie in the development of policies of rate making and principles of rate control designed to secure effective performance.[2] In fact, however, no such assumption is

[1] P. 37, *supra*. For a further discussion of the distinction between a functional and a nonfunctional conception of reasonable rates, see Chap. VIII.

[2] A further partial explanation may lie in the tendency of the public utility treatises to expound the principles of rate control as they have been developed in the case law. But legal thinking has not been highly analytical in its use of economic concepts; and its criteria of reasonable or nondiscriminatory rates are based, not so much on notions of functional efficiency as on traditional notions of "equity" and of property rights. By way of example, note Professor I. L. Sharfman's valid criticism of the Interstate Commerce Commission for its failure to

warranted, since the question of precisely what tasks should be assigned to public utility rates is highly controversial.

THE ROLE OF THE PRICE SYSTEM

The purposes served by the imposition of any given rate of charge for a specific public utility service, no less than the purposes served by a market-fixed price for a particular commodity such as a given grade of wheat, are largely (though not completely) predetermined by the fact that this rate is merely a tiny part of a whole universe of prices, including prices for other commodities and services and prices for labor (wages) and for other factors of production. This same statement applies also to the entire schedule of rates charged for different classes and amounts of service by a great public utility enterprise like the Consolidated Edison Company of New York or the Tennessee Valley Authority. For both of these enterprises, the function of rates is one of adaptation to the outside world of prices. "Reasonable" rates may therefore be viewed as rates reasonably aligned with other prices, including the prices of the commodities and services supplied by the nonutility industries.

But the nature of this function of adaptation or alignment can be understood only by reference to the larger part played by the nation's entire price system in the control of economic activity. A survey of "the role of the price system" is therefore called for. But the survey will be brief and elementary, since a thorough review would cover a large part of the entire field of economics.

THE DEFINITE ROLE OF PRICES IN A PURE-MARKET ECONOMY

For reasons to be noted in the following section, it is impossible to make general but precise statements as to the functions performed by the many different kinds of prices in a "mixed economy" such as that of modern capitalism. This economy has at its command instruments of economic control, such as taxation, subsidy, and rationing, partly alternative and partly supplementary to the forces of the market place—instruments that leave

make articulate the economic rationale of its "primary policy of seeking to make rates conform to worth of service." *The Interstate Commerce Commission*, Vol. III B (New York, 1936), pp. 691–692.

considerable leeway for legislatures and administrators, influenced by their notions of public interest or by pressure groups, to choose what role they wish different kinds of prices to play. Here, the precise functions of specific groups of prices are decided upon as a matter of policy, not just discovered by reference to the inherent characteristics of the price system. Only under the fictitious assumption of a pure-market economy, operating without central direction, can one ascribe a definite role to the whole price system, symmetrical with respect to all component prices. Nevertheless, there is a decided similarity between this archetypal role of prices in a pure-market economy and the modified roles played by specific prices in real life.

In a pure-market economy, then, all goods are produced for sale rather than for direct use or for free distribution; and all incomes are realized through the sale of these goods or else through the sale of the labor or the other "factors of production" that go into the making and delivery of the goods. Here, the role of prices is coterminous with that of the entire economic organization of society. It is characterized as that of controlling the distribution of scarce resources among multiple and competing uses. If the resources were not scarce, there would be no need to "economize" their use by means of a price system. But since many resources are scarce, and since most of them have alternative uses (coal for the production of electricity versus coal for the production of gas or of steel products, etc.), there is need for a complex of prices by means of which shares of each such resource are apportioned among the different alternatives.

This resource-distribution role of the price system is composed of many subroles, which can be classified and subclassified in various ways according to the purposes and convenience of the analyst. The simplest classification will serve present purposes: a threefold division suggested by Professor Samuelson in his introductory textbook on economics.[3] Under this division, the price system determines (a) *what* things shall be produced, and in what amounts; (b) *how* they shall be produced, and by what producers; and (c) *to whom* they shall be distributed. Thus, in an unregu-

[3] Paul A. Samuelson, *Economics, an Introductory Analysis*, 3d ed. (New York, 1955), p. 15. For a more elaborate sixfold classification, expanded from an earlier classification by Frank H. Knight, see C. Lowell Harriss, *The American Economy* (Homewood, Ill., 1953), pp. 13–18.

lated, pure-market economy, the price system would determine, among millions of other things, whether or not 60-cycle alternating-current electric power shall be generated and supplied in a given area and at what rates of output; whether the generation in this area shall be entirely by steam plants or entirely or partly by water power; and how the supply of the power shall be apportioned as between industrial users and residential consumers, and as between rich consumers and poor consumers. In these determinations, prices act both as an attracting force motivating people to produce for sale, and as a repelling force leading prospective consumers to restrict their demands. These offsetting forces are illustrated in the textbooks by the familiar tables and diagrams of supply and demand.

In a pure-market economy, the prices that perform these vital functions of an economic organization are not themselves determined, or even influenced, by any central authority. Instead, they result from the interaction of buying, selling, producing, and consuming activities of individuals or groups of individuals, each seeking to maximize profits or gains on sale and to minimize costs on purchase. But as a result of these interactions, there emerges a genuine economic system instead of a condition of chaos.

The nature of these interactions, even under the simplified assumptions of pure competition, is complex, as the uninitiated reader would discover by studying even as skillfully clarified an exposition as that by Professor Stigler in his book on *The Theory of Price*.[4] But the resulting allocation of resources among alternative uses is supposed to reflect a condition called "consumer sovereignty"—a crude phrase since the implied analogy of the market place to the voting booth is very loose. The preferences of the consumers, expressed in their bid prices or in their responses to asked prices, determine the kinds and amounts of products to be produced and also their distribution among different persons or "spending units." But the voting power (or, more accurately, the drawing power) of these different persons is weighted by their relative money incomes—incomes which, in turn, are derived from the sale of products or of productive services at market-determined prices.

How well the price system of a pure-market economy would

[4] George J. Stigler, *The Theory of Price*, rev. ed. (New York, 1952).

subserve the public welfare if it could be, and actually were, operated under conditions of strict or perfect competition is a question of doubtful meaning, to which no confident answer can be given if only because it assumes a form of economic organization that never has existed and never can exist. Any answer, moreover, would need to assume a standard of social welfare that at best is only plausible, not axiomatic, and that would surely fail to win unqualified public acceptance. But having in mind a standard of "economic welfare" which identifies maximum welfare with maximum satisfaction of individual consumer preferences, many economists have declared that, with certain exceptions or qualifications, the prices that would result without regulation but under pure or perfect competition would be the "ideal" prices. The import of such a statement, however, might well mislead a layman, or even an economist himself. For no scientific proof (nor any common-sense proof, for that matter) can be adduced for the proposition that an unmodified competitive-price system will lead to an optimum distribution of income among individuals and among families.[5]

Despite its limitations, the familiar assertion that competitive prices are, in a significant sense, "ideal" prices is of much interest to a student of principles of public utility regulation. For it supplies the major argument for a contention that the primary object of rate regulation should be to secure, by deliberate price control, those charges for public utility services that *would* prevail in the absence of regulation if the services were rendered under conditions of competition. The merits of this contention will be discussed in Chapter VI, "Competitive Price as a Norm of Rate Regulation."

[5] The standard work on the relationship between competitive price conditions and optimum economic conditions was written by Professor A. C. Pigou of Cambridge University: *The Economics of Welfare*, 4th ed. (London, 1932). The original edition, itself expanded from an earlier work, was published in 1920. Pigou's techniques of analysis have been much modified by later writers in the field of "welfare economics." But I doubt whether the revisions of technique have led to conclusions on rate-making policies notably different from those suggested by Pigou's analysis as revised by him in his later editions. The more recent literature has laid great emphasis on marginal cost, rather than average total cost, as a measure of optimum rates. See Chap. XX. But the general philosophy of marginal-cost pricing is suggested in Pigou's treatise as well as in earlier literature on price or rate theory.

THE FLEXIBLE ROLE OF PRICES IN A MIXED CAPITALIST ECONOMY

In the theory of price determination under the assumption of a pure-market economy, the role of the price system is predetermined by the very definition of this economy. Here, price fixing or price regulation would not be available, say, as an instrument for the relief of drought-ridden farmers in Southwestern United States, or as part of a government program for the stimulation of industries deemed of critical importance for national defense, or for the purpose of discouraging the consumption of liquor through the imposition of heavy excise taxes. In short, specific prices or groups of prices are not determined by reference to specific price-making policies. Samuelson has this point in mind in warning the reader that the failure of a competitive market economy to distribute goods on the basis of relative needs rather than on the basis of money demand is no sign of its failure to perform efficiently the functions that it is designed to perform.[6] A charge of inefficiency on this score would be just as pointless as would be a complaint that a typewriter is inefficient because it fails to correct a typist's misspellings.

Even when we turn to a mixed economy like that in the United States of today, an exposition of the role of prices in a pure-market economy fits the situation fairly well if not pressed too far—much better, in fact, than would any alternative simple exposition. For the economy of modern capitalism is not *hopelessly* mixed, and the forces of the market place are still dominant in the determination of relative prices of commodities and services—even in the determination of the regulated prices charged by public utility companies. It is for this reason that we can still refer usefully to the role of the price system as an organic whole; and it is for this reason that we can go a long way toward a derivation of the functions of any one price or group of prices, such as the functions of the rates charged by the Consolidated Edison Company of New York or by the Pennsylvania Railroad, by assuming that these functions are not fundamentally different from those performed by other prices, including the prices of wheat, of electrical equipment, or of laundry service.

[6] *Economics*, p. 37.

The force of this statement will be brought out in the following pages, which distinguish four primary functions of public utility rates. For this fourfold classification of functions also reflects the major functions performed by the unregulated prices of any one commodity or group of commodities. But the limitations of this statement will also be apparent as the discussion proceeds. For a mixed economy has at its disposal a variety of economic controls ancillary or alternative to that of the price system, with the result that, in the performance of any given function, price may merely assume *some share* in getting the desired result. What this share shall be is a question of policy that cannot be decided in the same way for all types of prices, or even for all public utility prices. It follows that the writer on public utility rate theory, no less than the writer on any theory or program of reasonable or optimum prices in a mixed economy, cannot rest content to take as "given" for his purposes the precise tasks to be assigned to the prices under review, limiting himself to an attempt to secure prices best designed to perform these predetermined tasks. On the contrary, he must assume responsibility for an attempt to resolve controversies as to how programs of rate making should cooperate with other policies of public utility operation and regulation in securing basic objectives of public policy. This problem of deciding precisely what role should be assigned to public utility rates with respect to particular types of utility enterprises and under different schemes of regulation is one of the most difficult and most controversial issues of modern rate theory.

THE FOUR PRIMARY FUNCTIONS OF PUBLIC UTILITY RATES

Without here attempting to answer the question what functions *ought to be* assigned to public utility rates, let us now review the main functions that these rates, in combination with other instruments of social control, are actually called upon to perform for American railroads and public utilities, whether operated under direct public ownership or under regulated private ownership. These functions can be classified in different ways; indeed, a thorough analysis of the role of utility rates would call both for

subclassification and for cross-classification. But a study of the many controversies about standards of reasonable rates to be found in the literature and in the litigated rate cases leads me to distinguish four primary functions. The significance of the distinctions, for purposes of rate theory, lies in the association of these different functions with different criteria and measures of reasonable or optimum utility rates. Indeed, the standards of efficient performance of these functions are in partial conflict with one another, with the result that sound rate-making policies are necessarily policies of wise compromise.

In default of more clearly established terms, the four functions to be distinguished may be called, respectively, (1) the producer-motivation or capital-attraction function; (2) the efficiency-incentive function; (3) the demand-control or consumer-rationing function; and (4) the income-distributive function. All have their counterparts in the role played by any unregulated competitive price or group of prices. For example, the prices charged for hats, viewed from the standpoint of the community or the nation, have the economic tasks, operating in participation with the surrounding universe of prices, (1) of stimulating or encouraging the production and marketing of hats, (2) of rewarding or penalizing hat makers and hat sellers for efficiency or inefficiency, (3) of restricting the effective demand for hats, thereby making overt hat rationing unnecessary, and (4) of transferring a compensatory amount of purchasing power from those who wear the hats to those who make and market them. But the relative importance of these four functions, as well as the accepted standards of good performance, may differ as between regulated utility services and commodities or services produced without regulation and in a highly competitive market.

1. THE PRODUCTION-MOTIVATION OR CAPITAL-ATTRACTION FUNCTION

One of the most obvious functions of prices in general is that of motivating and enabling persons to participate in the production and distribution of commodities or services for which they themselves may have no direct use. This is also one of the most prominent and most widely recognized functions of public utility rates. Public utility companies are permitted to impose charges for their services largely in order to induce and enable them to supply these services and to make provision for their continuation and for their required expansion. If denied the opportunity to levy compensatory charges, they could not long continue operation in the absence of tax-financed subsidies.

This production-motivation function of prices gives rise to the capital-attraction standard of reasonable public utility rates. By this standard, "reasonable rates" are rates adequate to yield revenues that will cover all legitimate operating expenses plus a return on investment sufficient to maintain sound corporate credit and to attract required amounts of new capital. Rates below this level are deemed deficient because, at least in the long run, they will not enable the company to live up to its obligations to serve the community.

In public utility cases in which the general *level* of rates (as distinct from the rate *structure*) is at issue, the capital-attraction standard of reasonable rates tends to be accepted by commissions as the primary basis for their decisions. Even the representatives of the public utility companies will usually base their requests for a rate increase or their opposition to a rate decrease on the ground of need for credit-sustaining revenue. True, company counsel will also assert their *legal* rights under constitution or statute and will support these claims in part by considerations of fairness to investors. But, especially in recent years, these collateral claims are seldom asserted except in defense of rate increases which the company also claims that it would need to secure solely in the long-run interests of its present and prospective consumers.

Impressed not just with the desirability but with the utter necessity of command over capital as a means of corporate survival and growth, one might be tempted to accept the capital-attraction function of rates, with its correlative capital-attraction standard of a reasonable return, as the only function that needs serious recognition as a criterion of reasonable rates. Any other functions, such as the three others already mentioned, might be deemed purely incidental, with the result that the whole theory and practice of rate regulation would be limited to the determination of rates adequate to maintain the enterprise in sound financial health in the light of its needs for expansion. Indeed, one sometimes reads in the literature of public service regulation statements that suggest this conclusion.[7]

But no such conclusion would be justified, since the capital-attraction function is only one of several important functions of utility rates. Indeed, it is not even the most nearly indispensable function, which is that of demand-control or consumer-rationing. But postponing discussion of this latter point, let us now note reasons why efficient performance of the capital-attraction or production-motivation function cannot be accepted as the sole, or even as the overriding, objective of rate-making policy.

In the first place, the nation or the community is under no compelling necessity to require its public utility enterprises to maintain and expand service on a self-financing basis. If desired, deficiencies in revenues from the sale of service can be made good by tax-financed subsidies. Subsidized public utility and railroad enterprises, both privately and publicly owned, are by no means unfamiliar in American history. To cite two current examples, one may mention the heavy, though now greatly reduced, Federal subsidies to the domestic airlines and the subsidized service provided by the New York subway system since its acquisition by the city government. In recent years, this subway system has not even covered operating expenses despite an increase in fares from 5¢ to 10¢ and then to 15¢.

To be sure, practical or theoretical reasons may justify a conclusion that, save in unusual situations, resort to subsidies is undesirable and that a public utility should be permitted and required to charge rates sufficient to maintain financial self-sufficiency. Indeed, with important qualifications, this is the view taken in the present book. But in any attempt to develop sound principles of rate making, the undesirability of subsidized services cannot properly be taken for granted as a starting point for the theory of

[7] Thus a recently published book on electric rates declares: "Rates for electric service are nothing more than price tags which the electric utility places on the service it renders. As such, their ultimate purpose is to provide for the utility, in the aggregate, sufficient revenue to cover all operating costs and earn a fair return on the fair value of the property devoted to public use." Russell E. Caywood, *Electric Utility Rate Economics* (New York, 1956), p. 22. But Caywood himself later recognizes other objectives of rate-making policy, not merely ancillary to the objective of adequate over-all revenues.

utility rates. Instead, the merits or demerits of a subsidy should be subject to careful analysis.[8]

In the second place, even under the assumption that a public utility enterprise should be financially independent, the capital-attraction role of rates can reach only a certain distance in determining standards of reasonable pricing. For, under conditions of regulated monopoly, various alternative schemes of rate making, if skillfully administered, may all suffice to attract the required capital. This statement applies even to the determination of adequate rate *levels* for reasons discussed in the chapters on rate-level determination. But it applies even more obviously to the determination of proper rate patterns or rate structures. The good or bad attributes of the rate relationships within a given public utility system—the relationship, say, between domestic and industrial electric rates, or between rates for on-peak and off-peak service, or between railroad coach fares and Pullman fares—are by no means limited to those attributes bearing on the company's ability to earn an adequate over-all rate of return.

Finally, unless supported by standards of reasonable or optimum rates derived from other functions, the capital-attraction function offers only a standard of *minimum* rates. True, as invoked in rate cases and in the literature, this function is usually construed to imply that reasonable rates are the *lowest* rates needed to maintain corporate credit and to permit the attraction of necessary new capital. And this is a very sensible construction in the normal situation. But one cannot derive this construction as a mere corollary of the proposition that public utility rates must be sufficiently high to attract capital. One must look to other functions of rates, notably to the consumer-rationing function and to the income-distribution function, for a reason in favor of the *lowest* capital-attracting rates.[9]

[8] This view may be contrasted with that expressed by Admiral Ben Moreell, then chairman of the board of the Jones & Laughlin Steel Corporation, when he declared: "I believe that all public power which is subsidized by tax funds, whether on the federal, state, or local level, is economically and morally wrong." Quoted in *Electrical World*, May 12, 1958, p. 55.

[9] In one important respect, the capital-attraction role of utility rates differs from the similar role played by unregulated, competitive prices. A private, non-utility producer is under no legal obligation to expand output beyond the point that he deems desirable on grounds of profit-maximization. But most public utilities are under a legal duty to supply adequate service within their franchise territories. Hence, they lack the freedom enjoyed by private businesses to base their expansion program on an estimate of profitability.

2. THE EFFICIENCY-INCENTIVE FUNCTION

Under unregulated competition, the price system is supposed to function in two ways with respect to the relationship between the price of the product and the cost of production. In the first place, the rate of output of any commodity will so adjust itself to the demand that the market price will tend to come into accord with production costs. But in the second place, competition will impel rival producers to strive to reduce their own production costs in order to maximize profits and even in order to survive in the struggle for markets. This latter, dynamic effect of competition has been regarded by modern economists as far more important and far more beneficent than any tendency of "atomistic" forms of competition to bring costs and prices into close alignment at any given point of time.

In the regulation of public utility monopolies, the principle that rates should be set at levels designed to yield revenues covering cost including or plus a "fair rate of return" may be regarded as a substitute, though not a close substitute, for the tendency of prices and costs to come into accord under the forces of market competition. But where is the efficiency-incentive counterpart?

Under prevailing methods of rate regulation, such incentives are, indeed, provided to a limited degree. First, private companies receive no guaranty of their ability to enjoy a "fair rate of return," with the result that they may be under more or less severe pressure to practice operating economies and to stimulate growth of demand for service in order to earn the officially sanctioned rate.[10] Second, the standards of a commission-fixed "fair rate of return" are themselves somewhat flexible, and some commissions, in setting these rates, try to make allowance for supposed relative efficiency or inefficiency of operation and of financial planning. And third, there is the so-called "regulatory lag"—the quite usual delay between the time when reported rates of profit are above or below standard and the time when an offsetting rate decrease or rate increase may be put into effect by commission order or otherwise.

[10] The significance of this no-guaranty situation is enhanced by the general refusal of commissions and courts to recognize past deficiencies or past excesses in corporate earnings as grounds for offsetting allowances in later rate cases.

But these incentive-encouragement features of orthodox rate regulation are extremely crude, and one may suspect that they are very ineffective in comparison with the stimulation of direct and active competition. Whether or not the situation lends itself to material improvement, through the adoption of systematic differential rates of return based on estimates of relative efficiency, is a controversial question, about which something will be said in Chapter XV, "The Fair Rate of Return."

3. THE DEMAND-CONTROL OR CONSUMER-RATIONING FUNCTION [11]

Although the capital-attraction function of public utility rates is the one that has had the most influence in the determination of American principles of rate regulation, it is not the function given first place by those modern economists who have written on rate-making theory. Instead, the function which they have emphasized is that of "demand control" or "consumer rationing." [12] Here, the price is designed, not to induce production but

[11] This function of price is often referred to in modern economics as a "resource-allocation function"—the function of allocating scarce resources among competing uses. But the latter term seems to me to be unhappily chosen for the purpose of designating the transactions that it is designed to cover. Logically, the effect of a price on the distribution of income among different persons is a resource-allocation effect. Yet, in practice, economists have distinguished between income-distributive effects and what they have called resource-allocation effects. See, e.g., Abba P. Lerner, *The Economics of Control* (New York, 1947), who distinguishes "The Optimum Distribution of Goods," *given* the individual-income distribution (Chap. 2), from "The Optimum Division of Income" (Chap. 3).

[12] The difference in relative emphasis placed upon this function of price fixing marks perhaps the major distinction between the outlook typical of the professional economist and that typical of popular and legal thinking. As recent writers have noted, neither the American public utility statutes nor the decisions of the public service commissions give primary attention to consumer-rationing or resource-allocative objectives of rate-making policy. Instead, the emphasis has been on a variety of other objectives such as those of capital attraction, of income distribution, and of "fairness" considerations. In commenting on a paper in which I had referred to the consumer-rationing standard of utility rates, Professor Emery Troxel declared that, under the rate-making policies of the Tennessee Valley Authority or the Bonneville Administration, "the rationing standard of Professor Bonbright's paper does not operate." With these Federal projects, he said, so much emphasis has been placed on the long-run maintenance of rate stability that "the public pricing policy is not directed either to a rationing purpose in short periods or to control of efficient allocative (investment) limits in longer organizational views." 47 *American Economic Review, Proceedings* 404 (May, 1957).

The same popular tendency to belittle or ignore resource-allocation objectives of economic policy has been found to exist outside the realm of utility economics. Thus Professor Melvin W. Reder, referring to the modern economist's objection to business monopolies on the ground that they tend to create a misallocation of productive resources (as distinct from the more familiar ground that they lead

rather to restrict or influence demand. When this function is performed efficiently, as is by no means always feasible in the regulation of utility rates, every potential consumer has the opportunity to receive forthwith, or after only a minimum delay, whatever type of service the utility enterprise undertakes to supply in his area, and in whatever amounts he is willing to buy at the scheduled rates of charge. Thus public utility rates are designed to avoid the necessity for overt rationing by making the consumer, in effect, ration himself.

In order to illustrate the high importance of this rate-making function, let us assume that the council of a large city which directly owns and operates its electric power system is considering a proposal to supply free electric service to all residents, and in whatever amounts each consumer requests. Let us also concede the financial feasibility of the proposal in view of the city's powers to pay operating expenses and fixed charges out of the proceeds of various taxes. What objections can be raised against this pleasant arrangement?

There are several possible objections, including the criticism that the plan would be unfair to those residents who are subject to high taxes but who have little need for electric service—a criticism relevant to the income-distributive function of utility rates. But another objection, even more serious, is that the offer of free

to a bad income distribution) says: "But this complaint is almost exclusively a complaint of the professional economist; indeed, the lay public is scarcely aware of the existence of a resource-allocation problem, let alone the role of the pricing system in its solution, and the implications of 'Monopoly' in connection with it." *Studies in the Theory of Welfare Economics* (New York, 1947), p. 47.

The recent writings by professional economists on urban transit problems have laid stress on the failure of public authorities to base their fare-fixing policies on demand-control objectives. Thus Wilfred Owen writes: "Along with this failure of the urban transportation system to meet the needs of modern communities, the possibilities of influencing transportation demand to bring it more nearly into balance with the supply of facilities have been almost completely overlooked." *The Metropolitan Transportation System* (Washington, D.C., 1956), p. 249.

But some recent economists have insisted that the majority of their profession have overemphasized consumer-rationing or resource-allocative objectives of rate making and price fixing to the neglect of other, assertedly even more important, objectives such as those of income distribution or income stability. With respect to farm-price controls, this criticism of the academic economists has been voiced sharply by Professor J. K. Galbraith: "Economic Preconceptions and the Farm Policy," 44 *American Economic Review* 40–52 (1954). It is also implied by writers who defend the application of a cost-price standard to the regulation of well-head prices of natural gas. See, e.g., Joel B. Dirlam, "Natural Gas: Cost, Conservation, and Pricing," 48 *American Economic Review, Proceedings* 491–501 (May, 1958).

and unlimited service would surely result in wasteful use of electric power. The waste would be most obvious with respect to the demand for industrial power, say, for the production of aluminum or for electrochemical industries. But in these days of modern electric appliances, it would be serious even with respect to domestic consumption, as the British have occasion to know in view of the prevailing below-cost charges for the peak-time use of electricity for house heating.[13]

Faced with this prospect of an excessive demand for electric service in the absence of any charge therefor, our hypothetical city would be compelled either to abandon the proposal for free electricity or else to introduce complex restrictions as to the amounts, the times, and the types of use. But the imposition of such restrictions would be a very clumsy and ineffective instrument of economic control, and the case against it would be overwhelming save, perhaps, in a period of emergency. Under normal conditions, a far better practice is a resort to the "automatic rationing" of a price system.

It remains to note an ambiguity in the terms "demand-control" or "consumer-rationing" when used to characterize a specific function of rates or prices. In its broadest sense, this function refers to any use made of prices as devices by which to affect the demand for the services to which the prices are attached or the demand for alternative or complementary services. Thus, if the city council in our imaginary city, on receipt of reports from medical experts on the amount of light needed to minimize eyestrain, were to decide that every family "needs" to consume electricity for lighting at the rate of 50 kilowatt hours per month, it would be resorting to a consumer-rationing standard of rate making if it should attempt to fix rates so as to encourage this amount of lighting use. A more familiar example of the same interpretation of a consumer-rationing standard of price is the supply of city water to dwelling houses at less than cost when justified on the ground that a liberal use of water is in the interest of community health.[14] And at the other extreme, although out-

[13] See *Report of the Committee on National Policy for the Use of Fuel and Power Resources* (The "Ridley Committee" Report), Cmd. 8647, London, Sept., 1952; also I. M. D. Little, *The Price of Fuel* (Oxford, 1953).

[14] The desirability of encouraging free household use of water for sanitary purposes has often been given as a justification for nonmetered water service, especially for the smaller users. In a defense of the use of meters, despite political

side the field of the public utilities, is the imposition of high excise taxes on liquor for sumptuary purposes rather than merely for revenue-raising purposes.

But as the term is usually construed in price or rate theory, the "consumer-rationing" function does not refer to the use of prices by the government as a means of allocating commodities and services to different individuals on the basis of centrally determined needs. Instead, the prices are designed to let the consumer be the judge of his own needs or wants, subject, however, to the requirement of compensatory payment. This is the principle of consumer sovereignty, the most fundamental single principle of modern public utility rate theory.

Under conditions of unregulated competition, prices are supposed to adjust themselves "automatically" in accord with this principle of consumer sovereignty. The desired result takes place because the competitive price is, in a sense, an indemnity price—a price, the payment of which by the consumer covers the costs (including the so-called "opportunity costs") incurred by those persons who supply the required "factors of production." Under regulated monopoly, there is no such automatic adjustment. Instead, the adjustment must be brought about by the aid of policies of rate regulation expressly designed for this purpose. This involves a system of modified cost pricing. But, as we shall note later, there are formidable difficulties in the way of a successful application of such a system—among them, the difficulty arising when rates sufficient to cover the incremental costs of the different services, considered separately, would fail to cover all the overhead costs.

The prominence here given to the function of utility rates in restricting the demand for service to those demands for which consumers are ready to cover costs of rendition may seem shocking to persons familiar with the emphasis placed by modern ratemaking practice on so-called "promotional rates"—on rates expressly designed to stimulate increased use of public utility services including, particularly, use of electric energy. This abundant-

resistance thereto, Mr. Harry E. Jordan, Secretary of the American Water Works Association, Inc., has declared that "when cities have gone from an unmetered to a fully metered basis the records show a reduction from one-third to one-half of the prior use per person." But he adds: "No one has suffered. No citizen has had to 'go dirty.' He simply stopped letting faucets drip and water run unnecessarily." Letter to New York *Times*, Oct. 2, 1954.

use philosophy of rate making has won qualified acceptance among the private utility companies within the past twenty years. But it has been accepted with greatest enthusiasm by some of the spokesmen for public power, who have been charged by critics with carrying their enthusiasm to an irrational excess.

The merits of this criticism could hardly be appraised intelligently without reference to specific claims on behalf of the public-power advocates. But in any case, there is no inconsistency between the view that rate schedules should be promotional in character and the view that an important function of rates is that of preventing wasteful consumption.[15] A promotional rate schedule is simply a schedule that lowers the price barriers against incremental blocks of consumption. Only if these barriers are lowered to the point at which incremental use fails to cover incremental cost is there a violation of the consumer-rationing standard of rate making as here construed. In fact, a failure to lower the barriers to this point with respect to those utility services for which the demand is highly elastic indicates a departure from the consumer-rationing standard.[16]

4. THE INCOME-DISTRIBUTIVE FUNCTION

All three of the functions of public utility rates mentioned up to this point are tasks designed cooperatively to serve one common goal of rate-making policy: the provision of the community with adequate kinds and amounts of public utility services, produced in an economical manner. Thus, the rates charged for its services by a given public utility enterprise are designed (a) to determine the types and amounts of service that the enterprise must undertake to render, (b) to enable the enterprise to pay operating expenses and to attract the capital needed in order to render this service, and (c) to encourage the management of the enterprise to meet the demand for service at a minimum cost of production.

But a fourth rate-making function must now be distinguished: that of transferring, in the form of a cash payment, a desirable amount of purchasing power from buyer to seller, from consumer to producer, from the persons who receive the benefits to the persons who bear the burdens. This return flow of cash is here regarded neither as a mere means of stimulating production nor as a mere means of limiting consumption, but rather as a means of income distribution or redistribution.

In order to distinguish this income-distributive function from the other three, let us assume, contrary to experience, that the demand for electric energy by domestic consumers would be unaffected by any change in rates within a wide range—say, a range between 2¢ and 10¢ per kilowatt-hour. At either extreme or at any intermediate point, consumption per customer would stay fixed at 200 kilowatt-hours per month. Let us also assume that even the 2¢ rate would yield revenues quite adequate to enable the company to attract needed capital and hence that any higher rate, at least up to 10¢ per kilowatt-hour, would also yield revenues adequate for this purpose—in fact, *more* than adequate.

Under these assumptions, none of the rate-making functions so far discussed offers us a criterion of reasonable rates by which to prefer any rate between 2¢ and 10¢ over any other rate within the same wide range. For any one of these rates will meet equally well both the capital-attraction test and the consumer-rationing test. As to the efficiency-incentive test, its relevance is doubtful to the problem here under review. We must therefore look to a fourth standard of reasonable rates, the income-distributive standard. Under this standard, the question how much currency should be transferred from the consumer to the producer must be decided

[15] A public utility may promote the use of a specific type of service, not only by lowering the rate charged for this service but also by raising the rate charged for alternative types of service, thus taking advantage of what economists have called "cross-elasticity of demand." For example, off-peak consumption of the service may be encouraged by a reduction in rates for off-peak uses combined with an increase in rates for peak-time use.

[16] The problem of making utility rates perform most effectively a consumer-rationing role is rendered extremely difficult by the paucity of reliable data on the price-elasticity of demand for different kinds of utility service. This problem is complicated by the influence on demand of variables other than the rates charged for the services in question: by changes in demand resulting from changes in consumers' income, changes in the price of substitute or complementary services and commodities, and increases or decreases in advertising and in high-pressure salesmanship. For example, in determining the extent to which electricity will be put to various household uses, the form and level of the rates of charge can exercise only a participating influence along with the availability and the pricing of electrical equipment and along with the promotional activities of the company's commercial department. Some years ago, the manager of the Winnipeg Municipal Electric Plant told me that the effect of a drastic decrease in rates had proved very disappointing until the household use of electricity was spurred on by an intensive advertising program and by resort to an expensive and appealing showroom of electric appliances, located on Winnipeg's main shopping street.

"on its own merits" and not merely because of the effect of the contemplated transfer on producer or consumer motivation.

An answer to the question just raised calls for a relevant standard of income distribution in the sale of public utility services. But, here, two quite different standards are suggested in the rate cases and in the literature on public utility pricing. They may be called the compensation standard and the quasi-tax, or ability-to-pay, standard.

Under the compensation standard, the outflow of cash from consumer to producer is designed merely to offset or counterbalance the cost incurred by the producer in supplying the service. The consumer "accounts" to society, through the producer, for a draft on its limited resources, thereby reducing his own opportunity to purchase other commodities or services with a given income. In this way public utility rates participate with other prices in the task of making the relative *money* incomes of individuals determine their relative purchasing power, their relative "*real* income." But these rates are not designed to offset inequalities in money incomes as among different consumers, or as between consumers and producers.

Under the quasi-tax version of the income-distributive function of public utility rates, the prices that consumers pay for public utility services are not necessarily set at amounts designed to transfer the cost of supply from producer to beneficiary; nor are they designed to offset the value of the service to the beneficiary. Instead, the price mechanism is here used as an occasion to make some slight correction for unequal distributions of money income between producers and consumers, or among different classes of consumers. Here, for the first time, ability to pay becomes directly relevant to the determination of a "reasonable" rate.[17] But the ability-to-pay principle cannot be carried beyond severe limits, since any attempt to do so would lead to a breakdown in the other functions of utility rates.

In our hypothetical example of domestic service for which the demand is completely unresponsive to changes in price within a range from 2¢ to 10¢ per kilowatt-hour, the compensation

[17] One should be on guard not to confuse an ability-to-pay standard of reasonable rates with a value-of-the-service principle. For a comment on the distinction, see p. 111, n. 5, *infra*.

version of the income-distributive function of rates would require that the rate be set at 2¢, since this price suffices to cover cost including a capital-attracting rate of return. Even under a quasi-tax version the same answer may be given if we assume (a) that the corporate stockholders are richer than the domestic consumers and (b) that a uniform rate must apply to all of these consumers. But if the stockholders are poor and the consumers rich, then a 10¢ rate would be suggested by ability-to-pay considerations of reasonable rates.

Very wisely, in my opinion, the standard literature on utility and railroad rate theory expressly or implicitly supports the compensation version rather than the quasi-tax version of the income-distributive function of utility rates. That is to say, these rates are not regarded as instruments for an attempted correction of personal-income disparities, save in highly special cases, and then only as makeshift devices.[18] Taken as a whole, moreover, the actual practices of American rate regulation comport with this position of modern rate theory. But there is also no doubt that, in actual practice, ability-to-pay considerations have material influence in rate-making practice, although the extent of their influence is impossible to assess because their lack of a recognized, official standing in the law of rate making leads rate makers or rate regulators to mix them in vaguely with other considerations. In the regulation of the rates of private utility companies, which are held entitled to an opportunity to enjoy a "fair return" regardless of the income status of their customers,[19] the influence of ability-to-pay factors is most potent in the design of the rate schedules as distinct from the rate levels. It accounts for the failure of many rate schedules to recover full out-of-pocket costs for small consumptions of service; for the allowance by railroads and local transit companies of special fares (or, in extreme cases, free service) to classes of patrons with reputedly low incomes combined with reputedly high merits (clergymen); and for a part of the public hostility toward proposals by economists for the imposition of higher local-transit fares in metropolitan cities

[18] See on this point, pp. 111–112, 116–117, *infra*.

[19] But during the depression of the 1930s, income-distributive arguments were merged with "value-of-service" arguments in support of utility rate reductions that were not expected to yield standard or conventional "fair rates of return." See pp. 259–262, *infra*.

during rush hours and in rush directions—proposals quite justified on cost-of-service principles.[20]

In closing this exposition of the income-distributive function of utility rates, let me warn the reader that neither popular nor legal thinking on standards of reasonable rates draws the clear-cut distinction that I have attempted to draw between the "compensation" and the "quasi-tax" version of this function. Indeed, popular thinking betrays notions of "fair pricing," derived perhaps from the mediaeval conceptions of "just price" (*justum pretium*), which do not nicely fit either of these two versions. It reveals itself in a contention that uniform rates should be charged for services that are the same in some highly superficial or conventional sense, despite marked differences in cost of rendition: for example, uniform prices per kilowatt-hour of electric power regardless of time of delivery, or regardless of distance from the source of power, or regardless of density of the area to be served. A striking example of this point of view was given me, some years ago, by an official of the New York Farm Grange, who insisted that every farmer in the state of New York, however remote and isolated, "has an inherent right" to enjoy electric utility service on payment of the same rates paid by city dwellers. This contention, he felt, did not need to be proved valid on "economic" grounds since it followed from "the very nature of the public utility concept." Against such "natural-rights" points of view, scientific approaches to rate-making problems are impotent weapons.[21]

THE PROBLEM OF RECONCILING THE DIFFERENT FUNCTIONS OF PUBLIC UTILITY RATES

Under a system of unregulated but perfect competition as expounded by the classical treatises on economic theory, prices are supposed to perform all four of the aforesaid functions, in their competitive versions, with optimum efficiency. So far from being in conflict, the four functions are in perfect harmony. Indeed, no one function can be performed except in cooperation with the others.

[20] See p. 346, n. 7, *infra.*
[21] For a further discussion of this point of view, see Chap. VIII.

Even in the regulation of rates to be charged by a monopolistic public utility, there is a *large measure* of harmony among the correlative functions assigned to the rate-making machinery. As will be noted in the following chapter, this workable degree of harmony is attained by programs of rate making based on modifications of, and variations from, the principle of cost of service. Thus, rates based largely on cost may be designed, at one and the same time, (a) to make the enterprise self-supporting and to attract required new investment, (b) to restrict demand, and (c) to secure a return flow of cash consistent with the income-distributive function of prices in its more defensible version (the compensation version). Even the efficiency-incentive function of prices can be given some recognition, through flexible features in regulation of the type suggested in an earlier paragraph.

But in the determination of rate levels and rate structures for a regulated monopoly, a perfect harmony or perfect interaction among the various tasks assigned to these rates is impossible to secure. On the contrary, the functions are in partial conflict. By this I mean that the acceptance of rules or measures of reasonable rates designed exclusively to secure maximum efficiency in the performance of any single function would necessarily impair the efficiency of the same rates in the performance of some, at least, of its other functions. In consequence, the development of sound rate-making policies calls for a resort to wise compromise.[22] It may also call for consideration of proposals to minimize the conflict among the various tasks imposed upon the rate-making machinery by resort, on occasion, to alternative or ancillary forms of economic control including the use of tax-financed subsidies on the one hand and excess-profits taxation on the other hand.

The nature of these partial conflicts among the various purposes that public utility rates are designed to serve will be noted throughout the following chapters, which will also point to conflicts among subdivisions of each function and not just among the four primary functions noted in the present chapter. But the

[22] The fact that rate-making policy must seek to attain partly conflicting objectives and hence that it must resort to wise compromises is well recognized by the abler practical experts on utility rate making. L. R. Nash, *Public Utility Rate Structures* (New York, 1933), p. viii: "A basic purpose of this book is to portray rate making not as an exact, scientific procedure but as a skillful balancing of conflicting objectives."

fact that conflicts exist and that they create serious problems for the theory and practice of rate control may be illustrated here by two examples: first, that of a conflict between the capital-attraction and the efficiency-incentive functions of utility rates; and second, that of a conflict between the capital-attraction and the consumer-rationing functions.

The first type of conflict arises because, with a regulated monopoly such as an electric power company or a telephone company, financial experience strongly suggests that the type of regulation best designed to maintain corporate ability to raise capital is one which goes as far as feasible toward protecting the security holders against the risks of financial loss. In other words, maximum security rather than the sporting chance of high gains is the most effective inducement for this type of investment. This view is accepted by modern rate regulation, which undertakes to supply the financial security within limits. But if regulation goes too far in an attempt to supply this security, there arises the serious danger of a loss of managerial incentive toward efficient operation. And some writers believe that American rate regulation has gone well beyond this danger point in its readiness to give the capital-attraction function priority over the efficiency-incentive function of the price system.

The second type of conflict among functions of utility rates—that between the capital-attraction and the consumer-rationing functions—is of even more importance from the standpoint of rate theory. To be sure, performance of both of these functions calls for the acceptance of a cost-of-service standard of reasonable rates (or of reasonable *minimum* rates), with the result that there is a degree of harmony between the two functions. But the harmony is not complete, since the cost relevant to the capital-attraction standard is total experienced cost, whereas the cost most clearly relevant to the consumer-rationing standard is prospective incremental cost—the estimated additional cost of additional units of service. In consequence, the rates of charge that would be best designed to serve the one objective of rate making are not the most efficient rates for the attainment of the other objective. Standard public utility regulation is vaguely, though imperfectly, aware of this dilemma and attempts to meet it by discriminatory deviations from cost pricing of a "value-of-the-service" character.

On the other hand, some economists have supported another, more radical, escape from the dilemma, in the form of a proposal to base rates entirely on marginal or incremental costs, any resulting deficiencies in total revenue being made good by tax-financed subsidies.

But this chapter is not concerned with the merits of alternative ways by which to avoid or minimize serious conflicts among the different functions performed by public utility rates. Instead, it has been content merely to point to the existence of these conflicts and to suggest that the fact of this existence presents modern public utility rate theory with its most frustrating set of problems.

IV

COST OF SERVICE AS THE BASIC STANDARD OF REASONABLENESS

used in framework

In stressing the fact that public utility rates, like other prices, are usually designed to perform multiple functions, the preceding chapter distinguished four functions as primary under modern rate regulation. But only casual attention was paid to the question what *measures* of reasonable rates can be expected to secure satisfactory performance of these functions, together with the question whether rates best designed to perform any one function are also best designed to perform the others. A discussion of these two related questions constitutes the main subject of the remaining chapters.

Most of the treatises on public utility economics, following the case law on rate regulation, divide the subject of rate determination into two parts. The first part is concerned with the measures of a reasonable rate level for any one company or group of companies. The second part is concerned with the principles of the rate structure or rate differentials. This distinction is essential for purposes of analysis, and it will be observed in Parts Two and Three of the present study. But it suffers the disadvantage of cutting across certain basic standards of reasonable rates, such as the cost standard, which apply, though with variations, both to rate levels and to rate relationships. In order to minimize this disadvantage, the present chapter and those that immediately follow will use a different breakdown of subject matter. First, separate chapters will be devoted to the two most frequently cited criteria of reasonable rates—cost of service and value of service. Then will come a chapter on the standard of

hypothetical competitive price—a standard often thought to embody an ideal reconciliation of cost and value factors. In sharp contrast with the competitive-price norm is a group of related rate-making standards to be considered in Chapter VII, "Social Principles of Rate Making." Chapter VIII will reclassify the tests of reasonable rates by distinguishing between considerations of "fairness" or "equity" and considerations of "functional efficiency." Only in the last chapter of Part One, a transition chapter, will attention be turned to the distinction between rate-level standards and rate-structure standards.

THE WIDESPREAD ACCEPTANCE OF A COST-PRICE STANDARD

No writer whose views on public utility rates command respect purports to find a single yardstick by sole reference to which rates that are reasonable or socially desirable can be distinguished from rates that are unreasonable or adverse to the public interest. A complex of tests of acceptability is required, just as would be the case with the tests of a good automobile, a good income-tax law, or a good poem. Nevertheless, one standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and by public opinion alike—the standard of cost of service, often qualified by the stipulation that the relevant cost is *necessary* cost or cost reasonably or prudently incurred. True, other factors of rate making are potent and are sometimes controlling—especially the so-called value-of-service factor in the determination of the individual rate schedules. But the cost standard has the widest range of application. Rates found to be far in excess of cost are at least highly vulnerable to a charge of "unreasonableness." Rates found well below cost are likely to be tolerated, if at all, only as a necessary and temporary evil.

A cost standard of rate making has been most generally accepted in the regulation of the levels of rates charged by private utility companies. But even more significant is the widespread adherence to cost, or to some approximation of cost, as a basis of rate making under public ownership. Thus the great Hydro-Electric Power Commission of Ontario purports to apply the principle of "service at cost" in its charges for wholesale power supplied to the various municipal distribution systems of the province. And thus most of the Federal power projects in the United States, including the Tennessee Valley Authority, purport to sell electric power at rates designed to cover operating expenses plus a compensatory return on allocable capital investment—one form of a cost-of-service standard. To be sure, critics of these projects have insisted that, under proper accounting, revenues would be shown to fall short of full-cost coverage. But the mere fact that these allegations are generally denied by the responsible managements of the Federal agencies implies that these managements themselves concede the validity of a cost principle of rate making.

Lest the foregoing remarks be taken to imply an adherence to a cost standard more rigid than the facts would justify, let me at once note exceptions. In the first place, the principle is followed far more closely as a measure of general rate levels than as a measure of individual rate schedules. In the second place, it is deliberately violated by those municipal power plants, said to be fairly numerous, that use the sale of electricity as a source of large profits for the city treasury. And in the third place, it has been waived to a minor degree through the use of indirect subsidies in support of rural electrification in the United States; and waived to a major degree through the use of heavy subsidies for rural electrification in the province of Ontario. One may also note the huge deficits incurred in the operation of the Canadian National Railways, and the failure of most metropolitan transit systems, in recent years, to charge fares that cover operating expenses plus fixed charges.

Important, however, as are these and other deviations from a cost-price standard, they are generally treated as exceptions to the general rule of rate making. In Great Britain, even a Labor Government that went much farther than did this country in the direction of socialization, including socialized medicine, did not see fit to abandon the general criterion of service at cost when it nationalized its public utilities. Instead, it instructed the various boards, such as the British Electricity Authority, to undertake to realize total revenues sufficient to meet total outlays properly chargeable to revenue account, "taking one year with another." [1]

[1] The British statutes governing the rates to be charged by the nationalized public utilities and railroads do not expressly forbid sale of services at prices designed to yield revenues *in excess* of total costs. But they have been interpreted by British commentators as contemplating the provision of service "without making, so far as possible, either a deficit or a surplus." William A. Robson, ed., *Problems of Nationalized Industry* (New York, 1952), p. 335.

THE THREEFOLD RATIONALE OF A COST-PRICE STANDARD

No doubt one of the reasons for the popularity of a cost-of-service standard of rate making lies in the flexibility of the standard itself. "Cost," like "value," is a word of many meanings, with the result that persons who disagree, not just on minor details but on major principles of rate-making policy, may all subscribe to some version of the principle of "service at cost." The best known, though not the most important, illustration of such a disagreement is that between supporters of an "original-cost" basis of rate making and supporters of a "reproduction-cost" basis.[2]

But before turning attention to alternative meanings of "cost of service," let us first ask ourselves what reasons are advanced in favor of *any* cost-price standard of rate making—of any standard under which an attempt is made to transfer the cost of supplying the service from the producer to the consumer, no more and no less. The answer is that there are at least three related, though not identical, reasons, each one associated with a different function of public utility rates.[3]

The first support for the cost-price standard is concerned with the consumer-rationing function when performed under the principle of consumer sovereignty. Under this principle, potential consumers should be free to enjoy whatever kinds of service, in whatever amounts, they desire as long as they are ready to indemnify the producers, and hence society in general, for the costs of rendition. Only in this way can the consumers be put in a position, as it were, to ration themselves by striking a balance between benefits received and sacrifices imposed. If the rates were set at less than cost, either

[2] A more important disagreement is that between those who identify "cost of service" with some kind of average or prorated total cost, and those who identify it with differential or marginal or out-of-pocket cost.

[3] A fourth possible defense of a cost-price standard of utility rates is suggested by the British economist Professor W. Arthur Lewis as applicable to the British public corporations which now operate the major utility and railway enterprises. These corporations, he declares, should make neither a loss nor a profit after meeting all capital charges, because "to do otherwise is to contribute either to inflation or to deflation." Robson, ed., *Problems of Nationalized Industry*, p. 181. *

overt rationing would be necessary or else service would have to be supplied in wasteful amounts. If the rates were set at more than cost, use of the services thus priced would be unduly restricted.

But the pricing of public utility services at cost of production is supposed not only to bring about a proper control of demand; in addition, and at the same time, it is supposed to motivate and enable the producing company to supply the service in the amount demanded, thereby avoiding the need for resort to tax-financed subsidies. That is to say, the sale of the service at cost will supply the company with necessary revenues to pay operating expenses and capital charges. For this purpose, to be sure, cost must be given a broader definition than is customary in the language of accounting, since it must include allowance for a capital-attracting rate of return on investment. But a capital-attracting rate of profit is here considered a part of the necessary cost of service.

The third defense of the cost-price standard is related to the income-distributive function of rates in the more generally acceptable version that I have called, in Chapter III, the "compensation version." Under this version, an individual with a given income who decides to draw upon the producer, and hence on society, for a supply of public utility services should be made to "account" for this draft by the surrender of a cost-equivalent opportunity to use his cash income for the purchase of other things.[4]

Of the four primary functions of rates set forth in the preceding chapter, the only one that may require a deviation from *any* kind of a cost-price standard is the management-incentive function, which calls upon the price system to impose penalties for inefficient management, and to award special profits for superior performance. But even this function could be subserved, in theory at least, by a factitious definition of cost to mean, not necessarily the cost of service actually incurred under the existing management, but rather an estimate of the cost that *would be* incurred under a management of standard efficiency. The application of such a hypothetical-cost criterion presents formidable practical difficulties. But American

[4] Compare F. M. Taylor's discussion of price fixing in a socialist economy, in which Taylor declares that, under socialism, prices should equal cost of production in order to give meaning to any given income-allotment by the state to the individuals therein. "The Guidance of Production in a Socialist State," 19 *American Economic Review* 1-8 (1929).

regulation has attempted a very limited and crude application through the acceptance of the doctrine that, in public utility rate cases, companies may secure reimbursement only for "prudent" or "legitimate" or "reasonable" operating expenses and capital outlays. Some commissions, moreover, have purported to consider efficiency factors in their allowance of a fair rate of return.[5]

PARTIAL CONFLICT AMONG THE THREE OBJECTIVES OF A COST-PRICE STANDARD

In view of what has just been said, one might suppose that, with the possible exception of the management-efficiency function, all of the primary functions assigned to public utility rates could be performed in complete harmony, since all of them agree in calling for a cost-price measure of reasonable or optimum rates. That is to say, when utility rates are fixed at costs, they will simultaneously serve effectively (a) to keep the demand for the service within economic bounds without resort to overt rationing, (b) to enable and induce private capital to undergo the expenses of supplying whatever service is thus demanded, and (c) to transfer from the consumer beneficiaries to the producing enterprise, and hence to the suppliers of the "factors of production," compensatory amounts of purchasing power. This harmony of objectives under a cost-price system of rate regulation would thus be similar to the harmony of functions supposedly performed by unregulated prices when determined under the forces of market competition.

Unfortunately, however, the harmony attainable under a cost-price system of utility rates is far from complete. On the contrary, the functions are in partial conflict, sometimes seriously so. The major source of the conflict lies in the fact that a cost-price standard is subject to many different interpretations and that the interpretation which would best comport with any single objective of rate making is almost sure to be ill-adapted to the attainment of some of the other objectives. Some of the more serious dilemmas presented by different meanings of "cost of service" will be noted briefly in the following paragraphs.

[5] See Chap. XV.

ENTERPRISER COSTS VERSUS SOCIAL COSTS

A cost is always a cost *of* something *to* some individual or group of individuals. When cost of service [6] is offered as a measure of reasonable rates, the answer to the question, Cost to whom? may seem self-evident. Obviously, cost to the consumer is not the answer, since this cost is set by the very rates under review. Equally obviously, cost to the vendor would seem to be the relevant cost, since this is the only cost for which the vendor has a claim to compensation. Since the vendor is usually a private or public corporation, money costs to the corporation or "to the enterprise" would seem to be the proper criterion. Indeed, this is the interpretation generally placed upon a "cost-of-service" standard of rate making.

But if we view a cost-price standard of rate making, not merely as a means of enabling public utility companies to supply the required services at minimum prices, but also as a means of controlling the demand for these services—the consumer-rationing function—the acceptance of the enterpriser's cost as the only relevant cost is justified only under one important assumption: namely, that this cost reflects, with tolerable approximation, the sum total of costs or losses imposed upon the entire nation or community by the construction and operation of the utility plant.[7] If this assumption is valid, the consumers of the service, in indemnifying the public utility corporation or agency for money costs of production, are also indemnifying society for its total social costs. But if the assumption is invalid, then the theory of cost pricing faces a dilemma—that the payment of cost by the consumers to the corporate producer does not constitute full payment of cost or losses by the consumers to the whole community.

In the economic textbooks, the stock example of social costs of production not typically borne, at least not fully, by the producing

[6] This chapter will note only a few of the many distinctions between alternative meanings of "cost of service." For a much more exhaustive treatment, see John Maurice Clark, *Studies in the Economics of Overhead Costs* (Chicago, 1923). See also W. Arthur Lewis, *Overhead Costs* (London, 1949); Joel Dean, *Managerial Economics* (New York, 1951), Chap. 5, "Costs."

[7] The distinction, familiar to accounting, between a "cost" and a mere "loss" becomes blurred in the concept of social cost. By referring to the adverse consequences of purposive action, social costs seem to fall into the category of true costs. But in their inclusion of consequences that are adverse to "innocent bystanders," even though not to the actors, they seem to fall into the category of losses and not of costs.

firm or corporation, is the example of smoke, smell, and noise nuisances of plant construction and operation. Other unindemnified losses suffered by society as a whole or by "innocent bystanders" may be stream pollution, encroachment on the area's water levels, fire hazards, and consumption of limited natural resources (such as fuel oil or natural gas used in the generation of electric power), purchased by the producer at current prices that fail adequately to reflect their long-run scarcity values.[8]

But one must not assume that enterpriser costs always fall short of reflecting total social costs. Indeed, they may greatly exceed the *net* social costs of plant construction and operation, since they may include outlays by the public utility enterprise resulting in social benefits other than those derived from the use of the service. The most striking and important example of this possibility is that of a public utility plant constructed during a period of business depression, such as the deep depression which prevailed in this country during the 1930s. During this period, the money outlays for plant construction did not even roughly reflect comparable net social costs, since these outlays went largely to the employment of labor and plant that would otherwise have remained idle. This fact was well recognized by the national administration under President Roosevelt and by Congress, which granted heavy subsidies and loans for the construction of multiple-purpose dams and other public works projects.

The argument that enterpriser money costs are not even rough measures of the net social costs of producing public utility services, combined with the further argument that the prices which consumers will pay for services fail to measure the benefits received, forms the basis of those "social theories" of rate making to be discussed in Chapter VII. This argument is not accepted by most economists as justifying the general abandonment of a cost-price system of rate making. But it has special force in particular situations, or during a severe and prolonged business depression. When

[8] In the economic literature, the classical discussion of the distinction between social costs and private enterpriser costs is that by Professor A. C. Pigou, *Economics of Welfare*, 4th ed. (London, 1932), Chap. IX. For a recent monograph on the subject, see Professor K. William Kapp, *The Social Costs of Private Enterprise* (Cambridge, Mass., 1950). The analysis of this interesting book is somewhat limited by its failure to recognize that enterpriser cost, while it may fall short of total social cost, may also exceed net social cost.

these situations arise, they present rate theory with a serious dilemma. As far as possible, the dilemma should be avoided by efforts to bring enterpriser outlays into closer conformity with social costs —for example, by government action to compel public utility companies to minimize smoke nuisance even at considerable cost to them and hence to their consumers. Also to be considered is the possible use of a system of special utility taxation, designed to raise or lower the company's tax bills in recognition of social-cost differentials. But the practical difficulties of measuring social costs are formidable obstacles to their overt recognition as factors in rate determination.

TOTAL COSTS VERSUS COSTS OF SPECIFIC SERVICES

Let us now resolve the question, Costs to whom? by assuming that the relevant costs are the money costs to the public utility enterprise and turn to another question, Costs of what? Already this question is partly answered by the nature of the assignment, which is to measure the costs incurred in supplying public utility services. But any one company renders various kinds of service to many different consumers at many different rates of output and at different times. This circumstance gives rise to the question whether the significant costs are the particular costs of specific classes or units of service or whether the cost principle refers rather to a scheme of rate making designed to balance total revenues against total costs over some shorter or longer period of time.

In the regulation of private utility companies, and even in the rate-making practices of publicly owned plants, the determination of general rate levels is likely to take precedence over the determination of specific rate schedules; and there the most directly pertinent costs are the total costs, including the overhead costs. In other words, the cost principle is taken to mean that rates as a whole should cover costs as a whole. But even so, the specific rates are also based in part on cost calculations, and the problem of measuring the costs of separate classes and amounts of service is one of the most controversial problems in public utility rate theory.

We discuss this problem in Part Three, "The Rate Structure." For present purposes what is important to note is the fact that the sum of the costs specifically allocable to different classes and amounts of public utility service will not equate with the total

costs of supplying the services jointly, save under conditions rarely met with in actual practice. To be sure, public utility cost analysts have sometimes *purported* to apportion the total costs among the various classes of services so as to bring about the appearance of an equation between the whole and the sum of the parts. But this accomplishment is a tour de force of cost accounting, for reasons developed at length in Chapter XVIII. Hence there is an unavoidable partial conflict between a cost-of-service principle of rate making as referring to total cost, and a cost-of-service principle as referring to the costs of specific classes and amounts of service.

Where the objective of rate regulation is that of securing the lowest level of rates consistent with the avoidance of a public subsidy—and this is the primary objective of regulated private ownership in America—the major emphasis of the cost criterion is on total cost rather than on specific cost. In consequence, the design of the rate structure is based only in part on specific costs or cost differentials. But some modern economists, who lay great stress on the consumer-rationing function of utility rate making, would choose the other horn of the dilemma. That is to say, they would base utility rates on those costs that can be specifically assigned to definite types and amounts of service by a process of differential or incremental cost analysis. If the rates thus fixed should fail to yield total revenues sufficient to cover total costs including a fair return, these economists would have the government make good the deficiency by tax-financed subsidies.

SUNK COSTS VERSUS ESCAPABLE COSTS; ORIGINAL COSTS VERSUS REPLACEMENT COSTS

In America, a long-standing controversy as to the proper interpretation of the cost-of-service principle of rate making has been that between supporters of an actual-cost or original-cost basis of rate control, and supporters of a reproduction-cost basis, often associated with a "fair value" rate base. According to the former doctrine, rate levels should be sufficient to cover actual operating expenses plus a "fair rate of return" on the actual, depreciated cost of the utility plant and equipment; according to the latter, rates should cover operating expenses plus a "fair rate of return" on the depreciated replacement or reproduction cost of the properties, calculated on the basis of current price levels.

Direct discussion of this controversy will be reserved for later chapters, since it is both involved and confused in its objectives. But what concerns us here is the related, but more fundamental, distinction between "sunk costs" and "escapable" or "avoidable" costs as measures of reasonable rates or prices. The distinction is of critical importance for rate theory in the light of the contention, advanced by some writers on price economics, that the only relevant costs for purposes of price determination are the escapable costs. "Sunk costs"—that is to say, costs which, having already been irretrievably incurred, can no longer be avoided or minimized through a curtailment of output—are asserted to form no basis for rational future economic action. "In commerce," wrote a famous British economist, "bygones are forever bygones." [9]

With a public utility plant, a large fraction of the costly action needed to supply any particular output of service or stream of services will have been taken, and irrevocably taken, long before the services are delivered and long before the rates of charge therefor can feasibly be set. These "historical costs" should be completely ignored according to the opponents of "sunk-cost pricing." But their place, so it is argued, should be taken by estimates of replacement cost, of the cost that would be incurred to supply the service by a new plant of modern design, constructed at prevailing levels of prices. In short, the only cost of public utility services relevant for rate-making purposes is hypothetical replacement cost, not actual historical cost.

For reasons to be discussed at length in the chapters on the competitive-price standard and on the rate base, I do not believe that the arguments on behalf of replacement-cost pricing of utility services are well taken. On the contrary, I am convinced that some version of an actual-cost basis of rate making, with its frank acceptance of a sunk-cost price philosophy, is preferable for practical reasons and is by no means inferior for reasons of price theory. But the deficiencies of a sunk-cost standard of rate making should be recognized; and they are especially serious in the determination of the individual rate schedules as distinct from the general rate levels.

What, then, are these deficiencies? They are revealed most clearly by reference to the consumer-rationing function of public utility

[9] W. Stanley Jevons, *The Theory of Political Economy*, 4th ed. (London, 1911), p. 164.

rates. In support of this function, rates should be made just high enough to deter potential consumers from demanding services of types and in amounts for which they are unwilling to defray the costs of rendition. But for this purpose of demand control the relevant costs are those costs that can still be avoided by a restriction of output—in short, the escapable costs rather than the sunk costs. In a celebrated article on public utility and railway rate theory,[10] Professor Harold Hotelling illustrates this point by the example of a bridge which, despite a capacity far in excess of the total use that would be made of it even if it were toll free, is operated on a toll basis high enough to cover total operating and capital costs. This action by the toll-bridge authority in covering all costs including sunk costs will result in an uneconomic curtailment of service, a curtailment that will have only a trivial effect in reducing total costs since the major part even of the maintenance expenses is a function of time rather than of use. Hotelling therefore contends that, as long as the bridge has excess capacity, it should be kept toll free even though the operating and capital costs must be met by taxation. This means the abandonment of a cost-of-service standard of pricing in one sense of the term, the popular sense. But it means a transfer to another standard of cost pricing—the standard of incremental or marginal cost which, in the extreme example of the underused bridge, happens to be almost zero. The merits of this proposal will receive detailed discussion in Chapter XX and incidental attention in earlier chapters.

SHORT-RUN COSTS VERSUS LONG-RUN COSTS

Intermixed with questions of choice between sunk costs and escapable costs is the further question as to the period of time over which a cost-price system should attempt to equate rates on the one hand with costs on the other. Should the rates to be charged today be designed to equal the costs incurred today, or should a longer period of time—say a year or a cycle of four or five years—be chosen in which to keep rates on the average in line with costs on the average? If rates (or, at least, *minimum* rates) are to be based on marginal or incremental costs, should these cost increments be based on short-run or long-run assumptions as to the feasibility of a change

[10] "The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates," 6 *Econometrica* 242–269 (July, 1938).

in plant capacity in response to a change in demand for the service?

These are formidable questions admitting of no simple answers. Among the reasons for their perplexing character is the fact that they present dilemmas of rate-making policy that cannot be resolved by theoretical analysis because they do not represent choices, the adverse and favorable consequences of which can be balanced against each other in quantitative, mathematical terms. Concededly, for example, utility rates ought not to be too volatile and too unpredictable, as they would be if the attempt were made to let them respond to every shift in unit production costs. Concededly, also, they should not be too unresponsive to shifts in cost factors and in demand factors. But the problem of securing a wise compromise between excessive volatility and excessive stability must rely largely on "common-sense" solutions, with only limited help from economic analysis. More will be said on this point in Chapters XVII and XX.

COST PRICE AS A STANDARD OF COMPENSATION TO THE PRODUCER VERSUS COST PRICE AS A STANDARD OF PAYMENT BY CONSUMERS

Most discussions of the principle of reasonable pricing, whether with respect to the prices of public utility services or with respect to the prices of ordinary commodities, tend to assume that the sale of the service or the commodity represents a two-way transaction in which the payment made by the buyer-consumer represents the very payment received by the vendor-producer. Under this assumed identity between price payable and price receivable, a "fair" price must be a price alike fair to the buyer and fair to the seller, just as would be the case in a barter economy in which so many arrows are offered in exchange for one bow.

This tendency to assume an identity between the prices that consumers should pay for commodities and services and the prices that producers should receive as compensation for outlays and efforts in supplying the products persists throughout most of the law and literature of public utility rate making. But there is no such necessary identity; and on occasion, even American public utility and

railroad law has recognized distinctions between standards of reasonable compensation to producers of service and standards of reasonable payment by consumers. The possibility of drawing this distinction arises through the interposition of the government, or of some governmental agency, into the transactions of purchase and sale. On the one hand, the government may supplement the prices paid by consumers for utility services, thereby making the compensation to the producer larger than the burden on the consumers. On the other hand, the government may levy taxes on sales of service, or taxes closely related to such sales, thereby driving a wedge between the higher charges imposed on consumers and the lower rewards conferred on producers.[11] The first situation is illustrated by any of the various public utility subsidies, such as the airmail subsidies of domestic American air transport. The second situation is illustrated by the former "Recapture Clause" in the Transportation Act of 1920, under which railroads earning returns in excess of a certain standard percentage were required to turn over 50 per cent of the excess as a financial aid to "underprivileged" railroads. Under this law, Congress recognized that the rates which American railroads might reasonably exact from their customers might yield revenues in excess of a reasonable compensation for service rendered.[12]

[11] If the public utility taxes were designed merely to idemnify the public treasury for those costs of government, such as police and fire protection, that are imposed by the operation of the utility plant and business, the taxes could then be treated like any other cost of producing the service. But American public utility taxation does not have this limited objective. See pp. 402–406, *infra*.

[12] With the Recapture Clause, the ground for the distinction drawn by the Transportation Act between reasonable rates for consumers to pay, and reasonable compensation for producers to receive, lay in the practical necessity for uniform tariffs among the competing railroads in any one transportation area. In 1920 it was believed that tariffs high enough to maintain the credit of the higher-cost carriers would be higher than necessary to maintain the credit of their lower-cost rivals. In upholding the constitutionality of this clause, the Supreme Court, speaking through Chief Justice Taft, held that rates may be reasonable from the standpoint of the shipper even "though their net product furnishes more than a fair return for the carrier." Dayton-Goose Creek R. Co. v. U.S., 263 U.S. 456, 484 (1924). For an interesting commentary on this case and on the economic problem which it illustrates, see Robert L. Hale, *Freedom through Law* (New York, 1952), pp. 523–528.

Proposals to distinguish between reasonable prices for consumers to pay and reasonable compensation for producers to receive have been made as a solution of the farm price-control problem, alternative to the prevailing system of parity pricing. Such proposals, which have been adopted in England, were embodied

The merits of a policy of rate making which distinguishes between the standards of reasonable rates of charge for utility service and the standards of reasonable compensation to the producers of such service will be discussed in later chapters rather than in this preliminary chapter on cost-price standards. But the possible distinction between the two standards is noted here because of its bearing on the relevant definition of cost of service as a basis of rate making. Insofar as a cost-price standard of rate making is designed to yield revenues adequate, but no more than adequate, to permit a company to recover its necessary operating expenses and to maintain sound credit, it must be interpreted in a manner consistent with this objective of rate-making policy. This means, among other things, (a) that the relevant costs are enterpriser costs and not social costs, (b) that the important equation is between total revenues and total costs rather than between the rate for any specific service and the cost of rendering this particular service, and (c) that "cost of service" must be interpreted somewhat broadly to include an allowance for a capital-attracting rate of return. It also means that a strong, even if not conclusive, case can be made for an original-cost basis of rate making rather than a replacement-cost or an escapable-cost basis—a subject reserved for later discussion.

But insofar as the primary function of public utility rates is deemed to be that of optimum consumer rationing rather than that of producer motivation, a different conception of a cost-price standard of rate making is suggested. Among other things, (a) enterpriser cost is not a good price determinant unless it is acceptable as a rough measure of social cost, (b) the most obviously relevant costs are incremental or marginal costs rather than average total costs, and (c) costs that are "sunk" in the sense that they cannot be avoided or even minimized by denying service to potential customers should

in the "Brannan Plan" for the United States. Under the plan, farm products were to be priced at free-market prices, but the income of farmers was to be stabilized and, if necessary, fortified, by taxation.

Henry George's single-tax doctrine, under which the annual rental values of unimproved land would be completely or largely expropriated by government instead of by landlords, rests on the same essential distinction between the prices that consumers should pay for commodities or services and the proceeds of sale that the owners of the "factors of production" should be permitted to retain. See Paul A. Samuelson, *Economics*, 3d ed. (New York, 1955), Chap. 27, especially pp. 505–507. See also Kenneth E. Boulding, *Economic Analysis*, 3d ed. (New York, 1955), section on "The Attack on Economic Rent," pp. 724–725.

be excluded from consideration if their inclusion in the rates of charge would seriously restrict demand for the service.

Rightly or wrongly, American rate-making policy has made only sparing use of the machinery of taxation and of bounty in an effort to reduce the conflict between rates designed to yield adequate revenues to producers and rates designed to secure an optimum use of public utility service. Hence, regulation is compelled to approve rates that will be tolerably acceptable for both of the above-noted functions of pricing (producer motivating and consumer rationing) as well as for other functions. The prevailing American principles of rate making show the effects of this preference for compromise by a lack of sharpness in their details and by the acceptance of blurred concepts and measures of cost of service.

With this brief introduction to the nature and rationale of a cost-of-service criterion of public utility rates, we turn in the next chapter to the counterpart criterion, popularly called "value of service."

V

VALUE OF SERVICE AS AN ANCILLARY STANDARD

Despite a flexibility of definition which permits many variations in the meaning of "cost of service" designed to fit the special purposes of rate determination, the very nature of a cost standard gives it limitations that preclude its acceptance as the sole measure of reasonable public utility rates. Among these limitations is the failure of the cost principle to give direct weight to the value of the service to the consumers as distinct from the cost of production to the producers. While the relevance of cost is generally conceded, the contention is made that value should also be taken into account. This proposition is asserted to apply no less to the fairness of the prices charged for electric power, telephone service, and railroad transport, than to the fairness of the price charged by a tailor for a suit of clothes or by a department store for a lady's hat.

Writers on public utility rates who stress this position are not uniform as to how they would incorporate both cost and value components in the determination of specific rates. But perhaps the most frequent position is that a "reasonable" rate is one intermediate between cost of production as the lower limit and "value" of the service as the upper limit, the precise point being set by "practical" considerations rather than by any scientific rule of rate making.[1]

[1] Propositions of this character are plausible only if "cost" is narrowly defined so as to limit it to out-of-pocket cost or marginal cost, the receipt of any additional revenues being justified as reasonable compensation for overhead costs including or plus a fair rate of profits. For statements of the position of leading spokesmen for the public utility companies, see L. R. Nash, *Economics of Public Utilities*, 2d ed. (New York, 1931), pp. 121–122; Alexander Dow, *Some Public Service Papers* (Detroit, 1927), p. 211; Henry L. Doherty, in National Electric Light Association, *Proceedings*, May, 1910, pp. 291–321, reprinted in Edison Illuminating Company of Detroit, *The Development of Scientific Rates for Electricity Supply* (Detroit, 1915).

EXAMPLES OF VALUE-OF-SERVICE PRINCIPLES IN RAILROAD AND UTILITY RATE MAKING

Postponing for later discussion the formidable problem of defining "value of service" so as to qualify it as a definite standard of rate making, let us first note examples of the actual use of a standard which, at least, goes under that name.[2] The most prominent American examples are those of railway freight rates. While both the class rates and the special, "commodity" rates for freight shipments are designed to reflect cost differences to a limited extent, they are notoriously and openly based, for the most part, on the so-called value-of-service principle. In line with this philosophy, the charges per 100 pounds for the transportation of the more valuable commodities between any given points are higher, often several times higher, than the comparable charges for the transportation of commodities with a low value relative to their weight or bulk. These differentials are admittedly much greater than any which could be justified by the higher costs of handling and insuring the more valuable shipments.

Among the nontransport utilities, perhaps the most overt resort to a value-of-service standard is that by the telephone industry, led by the Bell System. Under policies of rate making acquiesced in by most state public service commissions, a single telephone company serving an entire state will adopt a state-wide system of rates designed to yield adequate total revenues through the levy of higher charges on subscribers in larger cities than on subscribers for comparable service in smaller communities. In any given city, moreover, higher rates are quoted for business use than for residential use. To be sure, both of these types of rate differentials can be, and have been, defended to some degree on strictly cost grounds—the community-size differential on the ground that telephone switch-

[2] In the literature of public utility rates, three terms, all referring to noncost standards of rate making, are often used interchangeably or with only minor differences in meaning: "value of service"; "charging what (or in proportion to what) the traffic will bear"; and "rate discrimination." The latter term is in favor among economists as a synonym for "value-of-service" pricing. But defenders of the practice in actual rate cases are loath to characterize it by the invidious term "discrimination." See Chap. XIX.

ing costs increase more than in direct proportion to any increase in the number of subscribers; the kind-of-use distinction mainly on the ground that business telephone calls create more serious peak loads than residential calls. But the telephone companies themselves do not rely on this defense alone in rate cases. On the contrary, and particularly with respect to size-of-community differentials, their major emphasis has been on "value" considerations. In the larger communities, so the argument goes, telephone service is "worth more" than in smaller communities, since each subscriber has potential toll-free connections with more people.

As to the electric and gas utilities at the present time, the deficiencies and paucity of published cost analyses make it impossible to determine the effect of "value-of-service" principles on typical rate structures.[3] Few persons, however, would deny that these principles have influence in the direction of rate differentials not completely supported by cost differentials. The major influence is probably to be found in what, from a cost standpoint, are excessively heavy discounts for large quantities of electricity or gas—discounts offered even when the unit costs of supplying the larger quantities are not reduced by more favorable load factors.

All of the examples of value-of-service pricing so far offered are those concerned with the *structure* of the rates, with the rate differentials rather than directly with the general rate levels. Indeed, at least with respect to the relatively monopolistic nontransport utilities, rate-level determination has adhered far more closely to the principle of service at cost in the sense of total cost coverage plus or including a "fair rate of return." [4]

But with the railroads, the Interstate Commerce Commission has

[3] A recent monograph by Ralph K. Davidson entitled *Price Discrimination in Selling Gas and Electricity* (Baltimore, 1955) concludes that current rate differentials are by no means justified on a cost basis. Other experts have expressed the belief that Davidson grossly exaggerates the extent of the deviations of rates from costs. However this may be, one should not assume that a failure of relative rates to correspond closely to relative costs means that they must therefore necessarily be based on value-of-service factors. Most rate patterns are to a material extent the outgrowth of historical developments, of political pressures on public service commissions, of popular prejudice, and of questionable theories of cost analysis. This statement applies alike to publicly and privately owned utility enterprises. It is only fair to add my conviction that the electric utilities, in recent years, have taken the lead in closer approaches to a rational system of rate making, the greatest lag being that on the part of the railroads.

[4] But so-called value-of-service considerations have probably influenced public service commissions in their findings as to what constitutes a "fair rate of return." See p. 138, *infra*.

sometimes declined to sanction the full rate-level increases requested by the carriers, not on the ground that lower rates would suffice to yield a "fair rate of return," but on the ground of serious doubt whether the higher rates would yield higher net income, at least over the longer run.[5] A refusal on these grounds is based on value-of-service considerations in one sense of this highly ambiguous term.

A significant though vain attempt to invoke a "value" standard of reasonable rate levels in the interest of consumers was made by the Wisconsin Public Service Commission during the depression of the 1930s. In 1934 the Commission ordered the Wisconsin Telephone Company to reduce its rates, not on the ground that they were yielding a rate of return that would be judged excessive by tests applicable to normal years, but rather on the ground that some decrease in rates was called for in response to the reduction in general price levels and in consumer incomes.[6] In an opinion speaking for the Commission, Chairman Lilienthal made the point that the depression had resulted in a decrease in the (money) *value* of telephone service. But the Commission's order was overruled by the Wisconsin Supreme Court, which held that even a severe business depression did not deprive the utility company of a constitutional right to the enjoyment of an opportunity to earn a "fair rate of return."

In thus using value-of-service language in partial defense of the rate-reduction order, Chairman Lilienthal doubtless hoped to secure support from an early, cryptic dictum by the Supreme Court in the famous case of *Smyth v. Ames*.[7] In this dictum, the Court de-

[5] Sharfman, *The Interstate Commerce Commission*, Vol. III B (New York, 1936), Chap. XIV. Railways have complained bitterly against refusals to grant rate increases on the ground that the increase would be ill-advised even from the applicant's point of view. The subject is an important one from the standpoint of sound regulatory practice. I am deliberately slighting it, however, in this book, since it involves an issue of legal jurisdiction rather than an issue of rate theory.

[6] See p. 261, *infra*.

[7] Smyth v. Ames, 169 U.S. 466 at 546–547 (1898). For discussions of the possible meaning of the dictum, see my *Valuation of Property* (New York, 1937), pp. 1108–1110; Robert L. Hale, "Non-Cost Standards in Rate Making," 36 *Yale Law Journal* 56–67 (1926); Eleanor Heyman, "Value of the Service; Its Various Meanings and Uses," 9 *Journal of Land and Public Utility Economics* 252–265 (1933); Henry H. Edgerton, "Value of the Service as a Factor in Rate Making," 32 *Harvard Law Review* 516–556 (1919); Hillyer Brown, "Value of the Service as a Ceiling on Public Utility Rates," 33 *California Law Review* 283–297 (1945); Clyde O. Fisher, "Value of the Service and Public Utility Rates," 12 *Journal of Land and Public Utility Economics* 76–83 (1935).

clared in effect that a company supplying a public service might not be denied an opportunity to charge rates that would yield a "reasonable return on the fair value" of its property devoted to the public service. But it qualified this statement by declaring that the consuming public has an overriding right to enjoy service at rates no higher than "what the service is reasonably worth."

Although this qualification of the "fair value" rule was repeated by the Supreme Court in later cases, its import remains a mystery. The mystery lies in the question how the Court could have assumed that any company, however greedy and however possessed of monopoly powers, could coerce free men and women to buy its products or services at more than they are worth. Obviously, "reasonably worth" must have been used in a normative, not in a positive, sense; but the nature of the norm has gone undefined to this day.

THE LACK OF A QUANTITATIVE DEFINITION OF VALUE OF SERVICE

Before considering the merits of a value standard as a basis of rate making one must first ask just what the standard means. This is no easy question, since the term has been used loosely, without benefit of any formal definition. One reason for the looseness is that, except when applied in special situations, "value" does not lend itself to quantitative expression as a measure of reasonable rates. Under a *cost* standard, the price per unit of service is supposed to be made equal to the cost per unit. But under a *value* standard, as ordinarily construed, one cannot first find that the value of the service is, say, 2¢ per kilowatt-hour or 10¢ per telephone call and then set the rate at this value.[8]

What has just been said is obviously true if "value" is taken to mean selling price or market value. For the price at which the service may be sold is the very point at issue in a rate case. But we are also in trouble, though of a different kind, if "value" here refers to the worth of the service to consumers as measured by the prices

[8] Referring to the use of the standard in railroad rate regulation, Professor Sharfman writes: "The 'value of service' principle, as a basis for rate-making, provides at best a vague and indeterminate formula, rather easily construed as justifying any system of rates found expedient by the carrier. Taking the words in their most obvious sense, no rate can exceed the value of the service and still continue to be paid by the shipper." Sharfman, *The Interstate Commerce Commission*, Vol. III B, pp. 321–322.

that they would pay rather than go without. Thus defined, the value of any given class of service will be different for different customers, and also different for various amounts of service delivered to any one customer. This variability in the values placed by different people on different amounts of any commodity or service at any one time is represented in the economic textbooks by "demand curves," which start with the relatively high prices that would be bid for small amounts of the product and which slope down to zero bid prices for redundant amounts. Of course, one might arbitrarily define "the value" of the service as the highest price for which *any* amount of service, however small, could be sold. But this definition would be useless for rate-making purposes. On the other hand, no specific intermediate price between the peak price and zero can be singled out as alone reflecting the value of the service,[9] no more than can one intermediate point on the side of a hill be picked out as reflecting the height of the side.

The fact that "value of the service" does not usually lend itself to quantitative expression as a measure of reasonable rates will be appreciated by anyone familiar with the use made of this type of standard in actual rate cases. Telephone companies, for example, insist that their service is "worth more" to subscribers in big cities than in little cities. But, to the best of my knowledge, they offer no evidence of the amounts of these values, city by city. The relative "values," if such they can be called, would seem to have merely ordinal, not cardinal, magnitudes. And the same statement would appear to apply to value-of-service pricing by the other utility companies and by the railways.

THREE DIFFERENT MEANINGS OF A VALUE-OF-SERVICE STANDARD

The foregoing remarks justify the conclusion, reached by writers who are meticulous in their use of economic terms, that "value of the service," when invoked as a criterion of reasonable rates or even

[9] Except in a case in which the maximum rate of output is predetermined by limited plant capacity, in which case the market-clearing price, as measured by the marginal bid, might be said to represent "the value of the service." But in most cases in which rates are said to be fixed on a value principle, the rate of output, so far from being predetermined, will depend on the amount of service demanded at the price to be fixed.

of maximum rates, is an inaccurate expression, and a misleading one unless the inaccuracy is clearly recognized. What, then, does the term really mean? The answer is that it has been used in a wide variety of senses.[10] But aside from its not infrequent use as a mere synonym for "fair price" judged by *any* standard or standards of fairness, the three alternative meanings that seem most significant are those set forth below.

1. MOST PROFITABLE RATE OF CHARGE

An earlier paragraph has suggested that, while "value of the service" *might* be defined as the highest price which any consumer would bid, if necessary, for any quantity of service, this definition would be useless for rate-making purposes. But a really significant price would be whatever price for a given service would yield maximum profits to the public utility company—possibly an exorbitant price but also possibly only slightly above out-of-pocket costs depending upon the product's cost functions and on the price elasticity of demand for the service ("what the traffic will bear"). In economics, such a price is called "the monopoly price" on the assumption that the objective of a monopolist is to maximize his net earnings. To be sure, this price does not represent the value of the product, in a nice sense of the word "value," any more than a variety of alternative prices at which the monopolist might be able to sell different quantities of his product. But business lingo lends some sanction to this use of words. Consistently with this usage, a public utility company which sets its rates, whether deliberately or through miscalculation, at levels higher than enough to yield maximum profits could be said to be charging "more than its services are worth."

The very fact that public utility rates are subject to regulation clearly disqualifies this version of the value-of-service standard as a *general* criterion of reasonable rates. But if, for reasons of competition or of a decline in the prosperity of the community, a utility company is unable to earn a "fair rate of return" under any feasible level and pattern of rates, a plausible though far from conclusive

[10] In the article cited in footnote 7, Professor Robert L. Hale, after a study of the language of commissioners and judges in rate cases, concludes that the term has been used on occasion to refer to *any* noncost criterion of rate making. I may add that it has also been used to refer to some standards more appropriately considered special types of a cost standard.

argument can be made for permission to exact whatever rates of charge will minimize the deficiencies in total revenues. This situation, which presents the rate regulator with a serious dilemma, will receive attention in Chapter IX.

2. RATE DISCRIMINATION

At least in the literature of economics, the "value-of-the-service" principle is taken most frequently to mean that principle of rate design under which the differences in the prices charged by a given enterprise for its various products are based, not just on differences in the costs of production but also in part on differences in the relative "price elasticities of demand." Products for which the demand will not be seriously curtailed by relatively high prices will be made to bear these prices. Products for which the demand will vanish or fade if the prices are set far above out-of-pocket or marginal costs will be priced nearer to these costs. This practice is called "price discrimination" in economics; and it is widely prevalent among public utilities and railroads despite the legal restrictions imposed by the rules against "unjust discrimination."

Viewed from the standpoint of the public interest, the restrained use of this version of a "value-of-the-service" principle is defensible chiefly on the ground that it is a *relatively* harmless means of making good the deficiency in total revenues that would result from the sale of all public utility services at mere marginal or out-of-pocket costs. To be sure, sale of utility services at some kind of average costs is a possible alternative method of full-cost coverage, in some respects a superior method. But it is inferior in other respects since it will sometimes preclude the consumption of services for which consumers would gladly pay more than incremental costs. For a further discussion of the subject, the reader is referred to Chapter XIX.

3. MARKET-CLEARING PRICE

Public utility rate theory suggests a third possible meaning of the value-of-service standard, that of a market-clearing price—a price just sufficient to secure full but unrationed use of service in whatever amounts are temporarily available in view of limited plant capacity. Such a standard would be applied by a toll-bridge authority if it were to set tolls just high enough to hold traffic within limits of safety and without inordinate delays. Similarly, it would be applied by a gas distribution company if, on facing a rapid growth of demand for natural-gas heating beyond the present capacity of its sources of supply, it were to raise its rates for service up to the point at which no demand at these rates would long go unsatisfied.[11]

Readers familiar with the textbook expositions of the theory of a competitive price will recognize the similarity of this possible market-clearing-price standard of rate regulation to the price-determining forces of an unregulated market, operating in "short-run" periods. But in actual practice public utility regulation makes very sparing use of the price system as a means of securing short-run adjustments between plant capacity and demand for service. More will be said on this point in the next chapter.

This chapter has discussed briefly a number of possible noncost standards of reasonable rates that often go under the name of value-of-service standards because of their direct reference to the benefit or demand side of public utility service as distinguished from the cost or sacrifice side. More will be said about them in the chapters of Part Three, on specific rate schedules. But enough has been said here to suggest that, in one of several versions—especially the second one noted above—they play important though subordinate roles in the modern theory and practice of rate regulation.

Why is the role subordinate to that of cost? The short answer is that the task of regulation is one of fixing values, not of finding them—of bringing the prices of public utility services into line with the prices of other products by relating the former prices to the costs of production. But this is an incomplete answer, and supplementary comments are called for.[12] Three such comments will serve to close the chapter.

[11] While this practice would constitute a violation of cost pricing in any usual sense of the term, it would be consistent with a cost principle in a special sense. For as long as there is an absolute limit to the number of customers who can be supplied, the granting of service to any one customer involves a social cost in the resulting necessity of denying the service to some other customer. What this other customer would pay for the service may be said to reflect the cost of the denial. Needless to say, however, it would not constitute a cost to the producer. See p. 393, *infra*.

[12] From the standpoint of economic theory, the major inadequacy of this reply lies in its failure to answer the question why the adjustment of public utility prices to costs of producing the services should not take place, as it is supposed to take place without regulation but under competition, *indirectly* through increases and decreases in the output of the services rather than by directly through price control. In short, why should not regulation substitute output control for direct price control? On this point, see pp. 99 and 335.

First, cost of service is itself affected by the values that individuals place thereon and hence by the demands that they make for services of different kinds and in different amounts. By way of illustration, consider the practice of electric and gas utilities in charging higher rates for service supplied at peak-time hours or seasons than for otherwise identical service at off-peak periods. Differential pricing of this nature is quite justified—indeed, it is required—by strict cost principles since increments in the output of service during peak periods impose additional capital outlays not imposed by increments in output produced at times when the plant is partly idle. But these cost differentials would not exist except for differences in the consumer demand for service at different periods of time.

Secondly, the lack of a coordinate status for cost and "value" factors in rate determination is also partly attributable to the lack of symmetry between the position of the producer and that of the consumer of public utility services. Unlike the situation prevailing in unregulated business, the producer is under a duty (qualified, to be sure) to supply services to all applicants in its franchise territory at the approved rates of charge and in whatever amounts the applicants are ready to pay for. On the other hand, the consumer of public utility service, like the purchaser of ordinary commodities, has the option to take as little or as much service as he desires to take at the filed rates. Having this option, he will presumably refrain from buying any service at rates in excess of its value to him. Under these conditions, any attempt to abandon a cost-of-service standard in favor of a value or benefit standard of rate making would have absurd results. Consumers to whom the service is of little value might then have the right to demand that the company supply it to them at this low value even though the cost of production might be ten times as high!

Thirdly and finally, in actual rate cases the cost principle is always given modified interpretations which, while not converting it into a value principle, take indirect account of the effectiveness of the cost incurrence in contributing to the benefit of the consumers. Thus, in principle at least, costs are subject to compensation only if prudently incurred; and thus, with some exceptions, a "fair rate of return" is allowed only on those capital outlays still embodied in properties "used and useful in the public service." [13] The refusal of public utility law to guarantee against losses, combined with the allowance of an opportunity to earn a reasonable profit for successful risk taking, are also related, though in a very crude way, to the principle of payment for benefit received and not merely for costs sustained. Finally, the tendency of commissions to base the allowance for these capital outlays on the original construction costs of the plant and equipment, even if the properties have later been sold to the present accounting company at higher or lower prices, rests on the principle that the only capital entitled to compensation is the capital usefully devoted to the service of the public.

[13] See pp. 173 and 214, *infra*. For a brilliant exposition of the relationship between the cost principle of rate making and a value, or service-rendered, principle, see Justice Jackson's dissenting opinion in Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 628–660 (1944).

VI

COMPETITIVE PRICE AS A NORM OF RATE REGULATION

Before turning in the next chapter to those unorthodox principles of rate making often called "social theories," we may consider the merits of a general standard of reasonable rates that has received at least verbal support both from public service commissions [1] and from public utility spokesmen.[2] This is the standard of the hypothetical competitive price. Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation but subject to the market forces of competition. In short, regulation should be not only a substitute for competition, but a closely imitative substitute:

[1] "The purpose of regulatory policy, in the protection which it is designed to afford the consumer, is to simulate and substitute the effects of competition and give the consumer the benefit which he would derive from a system of competition." From National Association of Railroad and Utility Commissioners, Report of the Committee on Progress in Public Utility Regulation, *Proceedings of the 53d Convention* (Washington, D.C., 1942), p. 369. Many commission opinions and a number of judicial dicta could be cited to the same effect.

[2] "The justification for the regulation of utility rates being the absence of competition, regulation should aim to produce the same results as competition would do if competition were economically desirable and feasible—neither more nor less." Brief for the New York Telephone Company in a case insisting upon its right, under the New York statutes, to receive the benefit of a "fair value" rate base that gives weight to reproduction costs. New York Telephone Co. v. Public Service Commission, 142 N.Y. Supp. 569 (1956). The brief cites, as supporting a competitive-price standard of reasonable pricing, Walter A. Morton, "Rate of Return and the Value of Money in Public Utilities," 28 *Land Economics* 91–131 (1952) and Arthur H. Dean, "Provision for Capital Exhaustion under Changing Price Levels," 65 *Harvard Law Review* 1339 (1954). See also C. P. Guercken, "An Economic Appraisal of the Private Electric Utility Industry," 55 *Public Utilities Fortnightly* 739–754 (1955).

This is a most intriguing proposition in view of the contention, familiar to economists, that competitive prices are optimum prices. One of its possible virtues is that it may offer definite answers to two formidable sets of questions raised in the preceding chapters: first, questions as to the relevant definitions of "cost of service" and "value of service"; and second, questions as to the respective roles of cost factors and of value or demand factors in price determination. Should "cost," for example, be taken to mean original cost or replacement cost, marginal cost or average cost, sunk cost or escapable cost? Let these and similar questions be resolved by a study of the types of costs that govern competitive-price determination. Should differences in rates of charge for different classes of service be based entirely on cost differences or should they depend in part on "value" differences (differences in the price elasticity of demand for the respective services)? Again, let the answer depend on the question whether firms producing multiple products under competition can and do practice price discrimination. And so on with respect to all of the other debated issues of rate-making policy.

During the postwar years of inflated price levels, the defense of a competitive-price standard has come largely from spokesmen for investor interests or for the public utility companies, who object to an original-cost rule of rate making on the ground that it unfairly deprives utility stockholders of the hedges against inflation said to be enjoyed by the owners of equities in unregulated enterprise. This is a forcible objection, the merits of which will be discussed in the chapters on the rate base and the "fair rate of return." But one may surmise that the alternative of a competitive-price norm would lose its charm for many of these writers were they to face the full implications of its adoption. In a dynamic economy, unrestrained competition is supposed to be a pretty tough game, often leading to individual or corporate bankruptcy.[3] "Fairness," in the sense of protection against the loss of hard-earned savings, is not one of its many virtues. Be that as it may, the view that a regulated monopoly should be induced or coerced to charge whatever rates would prevail under competition is so frequently urged, and so plausible in its appeal to economists, that it deserves

[3] "No war, no strike, no depression, can so completely destroy an established business or its profits, as new and better methods, equipment and materials in the hands of an enlightened competitor." From a statement by the Society for the Advancement of Management, repeatedly quoted in the issues of the magazine *Systems*.

sharp analysis. By way of introduction, let us therefore assume its acceptance and ask what rules of rate control would be required in order to put it into effect.

ASSOCIATION OF COMPETITIVE PRICE WITH REPLACEMENT COST

The popular conception of a competitive-price standard of rate making is much more primitive than any of its more sophisticated modern versions. But it is worth a brief exposition, since it probably still reflects the views of most practical rate makers who invoke the standard. It is derived from a simple exposition of the forces of competitive price determination to be found in the earlier textbooks on economics.

Under competition, then, prices are supposed to be determined proximately by the forces of supply and demand, and at a point set at the intersection of the curves representing these two offsetting forces. At any given time, the competitive market price may be much higher or much lower than the unit cost of production, and especially the unit *normal* cost. But any such discrepancy indicates a state of disequilibrium, which will tend to be corrected, even if the rate of demand for the product remains the same, by the expansion or contraction of output on the part of producers, acting under the attraction of profits or under the discouragement of deficits. Thus, there is a tendency for a competitive price to come into correspondence with normal cost of production; and this normal cost is sometimes said to represent the "normal value" of the product as distinct from its current market value.

Under the competitive-price standard of rate regulation, in its popular form, the object of regulation is deemed to be that of making the prices charged for public utility services conform to normal costs or normal values. But under regulation, just as under competition, these normal costs are not set by the actual or historical costs incurred by any given company by virtue of the prices paid in the past for the construction or acquisition of plant and equipment. On the contrary, the relevant costs are supposed to be the current and prospective replacement costs, since these are the only costs that would guide the action of competitive producers in their future decisions to expand or contract their output.

Thus, the competitive-price norm is brought to the support of a special version of the cost-price principle of rate making—a replacement-cost version that came to be closely associated, even though not completely identified, with the "fair-value" rule of rate regulation discussed at length in Part Two of this book. In the academic field, its most vigorous supporter has been Professor Harry Gunnison Brown of the University of Missouri, who for years waged a valiant fight on its behalf in the economic journals and against Justice Brandeis's increasingly popular "prudent-investment" principle.[4]

Properly qualified, the above-noted view of the nature of a competitive price, which led Brown and others to associate it with a price measured by replacement cost, cannot be said to have been discredited by modern price theory. But this theory has undergone developments that throw grave doubt on the relevance of a replacement-cost basis of rate control in its familiar sense.

Among these developments has been one which distinguishes important *types* of competition and which therefore destroys the earlier, simple distinctions between competitive and monopolistic pricing. The modern defense of any competitive-price norm of rate making therefore faces the necessity of defining the competition which it seeks to emulate. Is the proposed model that of "pure" or "perfect" competition? Or is it one of those mixed kinds of practical or "workable" competition typical of large-scale industry in this country?

Although few writers outside of academic economics have yet recognized the necessity of answering this question, those public utility representatives and public service commissioners who express approval of a competitive standard almost certainly have in mind a type of competition associated with fairly large-scale industrial companies, and not a type approximating the economist's concept of pure competition. Nevertheless, it will be worth while first to consider the implications of the standard of *pure* competition—competition bereft of monopoly elements—since this type is the only one that has been claimed by economists to offer a model of optimum pricing.

[4] See pp. 226–236, *infra*.

THE STANDARD OF PURE OR STRICT COMPETITION

For present purposes, pure competition may be defined as competition under which there exists no collusion among producers and under which no single producer controls a portion of the potential supply sufficiently large to give him any appreciable influence over the market price of his product.[5] It is "competition among the many." Here, unlike the situation of "competition among the few," each producer must accept the market price of his product as "given"; he has no opportunity to practice a "price policy."

The principles of price determination under assumed conditions of pure competition, as set forth in the modern textbooks,[6] are fairly complex, and I shall not here undertake even a brief summary. Instead, I propose to consider what rate-making criteria seem to be required by an attempt to make the rates that are in fact charged by a monopolized enterprise behave as if they were determined solely by the market forces of competitive supply and demand.

RATES SHOULD CORRESPOND TO PRODUCTION COSTS ONLY UNDER CONDITIONS OF EQUILIBRIUM

It is an elementary principle of competitive-price theory that the influence on price of cost of production is indirect and that the cost-price relationship states merely a condition of static equilibrium. At any given time, prices are set by the offsetting forces

[5] The terms "pure" and "perfect" competition are used sometimes as mere synonyms but sometimes with distinctions. Those who draw a distinction use the former term to denote any competition completely devoid of monopoly elements, reserving the latter for competition which, in addition to its purity, has other attributes of "perfection," notably, perfect two-way mobility of the factors of production (including contractability and expansibility of plant capacity in immediate response to changes in demand), and perfect foresight (itself a dubious concept). See Edward Chamberlin, *The Theory of Monopolistic Competition*, 6th ed. (Cambridge, Mass., 1950), p. 6; John Maurice Clark, "Toward a Concept of Workable Competition," 30 *American Economic Review* 241–256 (1940). As a norm of regulated monopoly pricing, "perfect competition" would make no sense. The objective of sound competitive rate-making policy should be to make the best use of whatever plant happens to be available in view of its noncollapsibility. And there is no point in assuming a greater degree of foresight than intelligent people can hope to enjoy at the time of a rate case.

[6] See, e.g., George J. Stigler, *The Theory of Price*, rev. ed. (New York, 1952), Part I.

of supply and demand and are likely to be materially above or below their normal production costs.[7] While they are *tending* in the direction of these costs, the adjustment of prices takes time and synchronizes with an adjustment of output. This lag in the adjustment process is not thought of as a defect of competition. On the contrary, a temporary disparity between cost and price is an essential device whereby the forthcoming supply of the commodity is brought into harmony with the demand.

It follows that a revision of the orthodox principles of rate regulation would be called for in any strict application of a competitive-price philosophy. Instead of the principle that utility rate levels should be raised or lowered so as to yield operating expenses plus a normal rate of profit, year after year, there must be substituted some rule of rate making which more closely emulates the competitive forces of supply and demand—forces under which rates will yield highly abnormal profits when there is a shortage of existing plant capacity, and under which rates will fall to mere short-run incremental or marginal costs of service when plant capacity is temporarily redundant. This objective can no more be accomplished under a replacement-cost or "fair-value" rule of rate making in its traditional form than under an original-cost or prudent-investment rule.

The drastic import of this aspect of a strictly competitive-price standard of public utility regulation will be apparent if we consider its probable consequences, first, in a period of severe business depression and, secondly, in a period in which the growth of plant capacity has failed to keep pace with the demand for the service forthcoming at "normal" rates of charge. During a depression, the forces of competitive supply and demand, if operating under conditions of strict competition, would soon bring rates down to temporary, marginal costs so low that the resulting revenues would probably bankrupt companies capitalized in the manner typical of public utility capital structures. On the other hand, during a period of plant shortage, rates might need to be raised drastically in order to preclude the necessity for rationing or in order to avoid a long waiting list of unsatisfied potential consumers.

[7] See, e.g., Alfred Marshall, *Principles of Economics,* 6th ed. (London, 1910), Book V. At pp. 401–402 of this great classic is an interesting comment on the invalidity of the assumption that, under competition, the market price at any given time will be likely to approximate reproduction cost.

IF MARKET-CLEARING RATES YIELD EXCESS PROFITS, A COMMISSION SHOULD COMPEL THE EXPEDITIOUS ENHANCEMENT OF PLANT CAPACITY

Under the prevailing rules of public utility regulation, decisions as to the proper policies of plant expansion are seldom made by the regulating agency. Instead, they are made by the management of the public utility company, motivated partly by the expectation that the investment in the larger plant will at least pay for itself, but partly by the legal obligation to supply, without unreasonable delay, all services demanded at the scheduled rates of charge.

This regulatory policy of leaving the responsibility for plant expansion in the hands of the corporate management would need to be abandoned, or at least modified, in an effort to make monopoly pricing behave like competitive pricing. For as long as plant capacity is inadequate, competitive rates will yield excess profits —profits that will fall to normal (or to zero under *some* definitions of profits) as soon as the plant has been enlarged to proper size. As trustees for investor interests, corporate managements would therefore be under impelling pressure to retard plant expansion in order to continue the sale of services at their high, market-clearing prices. Nor would the obligation to satisfy all prevailing demand suffice as an offsetting pressure; for this very demand will be kept from becoming embarrassingly heavy by the establishment of the market-clearing prices.

Thirty years ago, the point that the enforcement of a competitive standard of rate making must take place primarily through governmental control of the *investment* activities of a public utility company, rather than directly through control of rates under the rule of a "fair rate of return," was developed by Professor Bruce W. Knight in an article entitled "Why Not Regulate Investment Instead of Return?" [8] In a commentary on this article, published in the same periodical, I took issue with Knight's contention that such a change in the rules of regulation would be desirable and feasible. But there can be little doubt that control of investment would be required by a strict, competitive-price rule of rate making.

[8] 6 *Public Utilities Fortnightly* 406–419 (1930). Compare the proposals by Lerner and others for competitive-price simulation under outright socialism. A. P. Lerner, *The Economics of Control* (New York, 1947), especially Chaps. 5 to 7.

RATES WOULD BE REQUIRED TO EQUAL BOTH AVERAGE COSTS AND MARGINAL COSTS

Under conditions of competition, both the prices and the outputs of commodities are supposed to tend to reach an equilibrium position in which the prices are equal to average unit costs of production. But, in this same position, they are also supposed to equal their marginal or incremental costs—the additional unit costs of producing them at enhanced rates of output. That is to say, under competitive equilibria, average costs and marginal costs coincide.[9]

But this requirement of correspondence of prices alike to average cost and to marginal cost presents a dilemma under monopoly-price regulation. For, if the monopoly is operating under conditions of decreasing cost with increasing size—a condition often assumed to be characteristic of the public utility industries—it will be impossible to bring rates into accord with the average costs of the service without making *some* of these rates, at least, higher than marginal costs. One might as well attempt to draw a square circle! Hence, the very type of cost behavior that precludes the maintenance of *actual* competition in the public utility industries may also preclude the application of a standard of *hypothetical* competition.

THE RELEVANT COSTS WOULD BE FUTURE COSTS, NOT "SUNK" COSTS

Here we have the basis for the popular assumption that the competitive-price standard of public utility regulation calls for the fixation of rates at replacement costs rather than at levels that will yield a fair rate of return on the original costs of the utility assets. Under the assumed conditions of pure competition, the only costs that govern the actions of competing producers in their decisions to increase or decrease output are those costs that are still

[9] Under the leadership of the great British economist Alfred Marshall, competitive-price theory has developed the concept of multiple equilibria, under which the earlier simple division between short-run (or virtually instantaneous) and long-run price determinants has been superseded by a recognition of a series of short, longer, and still longer runs, depending on the time required for more or less complete readjustments of plant capacity and of rate of plant output designed to meet prevailing demands. This complication will not be introduced in the present chapter, although it is important for utility-rate theory, especially so in raising the question whether the relevant marginal costs are long-run or short-run marginal costs. See Chap. XVII.

under the producers' control. A competitive price has no tendency to rise and fall in such a way as to cover costs of production already irretrievably incurred—not, that is, unless these sunk costs happen to coincide with anticipated escapable costs.

However, this principle of competitive pricing, characterized by the aphorism that "in commerce bygones are forever bygones," by no means supports the replacement-cost or "fair-value" basis of rate making in its orthodox, American sense. For, in the first place, replacement cost has here been identified with the estimated cost of a substantially identical plant rather than with the estimated cost of replacing the service by the most economical modern substitute. And in the second place, the replacement-cost or "fair-value" principle of rate making, in undertaking to make total corporate revenues equal total replacement costs of service including a fair rate of return, ignores the other requirement of competitive-price equilibria—that the specific rates should equal the marginal costs of the specific services.

ALL RATE DISCRIMINATION WOULD BE OUTLAWED

According to the treatises on price theory, the practice of price differentiation based on "value" or demand-elasticity differences rather than on cost differences would be impossible under conditions of strict or pure competition. This practice constitutes discrimination; and the power of a seller to discriminate, with profit to himself, is held to be limited to sellers possessing at least some degree of monopoly power.

Even under existing regulation of railways and public utilities, the law places limits on the right of a company to practice rate discrimination. But what the law forbids is merely certain types or degrees of discrimination which, for one reason or another, are deemed adverse to the public interest; for example, so-called "personal discrimination." No such distinction between just and unjust forms of discrimination could persist in a thoroughgoing attempt to apply competitive-price theory to railway and utility rates. The whole practice of rate fixing based even in part on "what the traffic will bear" would have to be outlawed.

THE RATES OF RETURN SHOULD CORRESPOND TO THE PROFIT-AND-LOSS DIFFERENTIALS OF A COMPETITIVE ECONOMY

In a dynamic economy, the function of competition is by no means limited to that of bringing about a more or less gradual adjustment of prices to costs of production. An even more important function is that of stimulating innovations and improvements in products and in techniques of production.[10] To this end, competitive business is not business conducted strictly at cost, nor even at cost plus a "fair" profit. Instead, it is business transacted at prices temporarily yielding very high rates of profit under efficient or lucky promotion and management and yielding substandard returns or even operating deficits under inefficient or unfortunate operation.

Under any regulation designed to make the prices charged by regulated monopolies perform in the manner in which competitive prices are supposed to perform over the years, public service commissions would face the problem of setting these prices so as to approach the differential profit-and-loss status of competitive industry and so as to break away from the fairly standardized "normal profit" status of orthodox regulation. This is a truly formidable assignment, and one which, to the best of my knowledge, has never been accomplished effectively. To be sure, schemes of differential returns, designed to reward highly efficient or highly successful performance, have been tried out from time to time, occasionally with fair success during periods of stable price levels. But even if experience with these schemes had been such as to warrant general adoption, their acceptance would provide a very weak imitation of the behavior of actual competition in a period of rapid technological development. Something far more radical would be imposed by the standard of simulated competition.

[10] During his chairmanship of the Federal Power Commission, Leland Olds stressed this function of a competitive price and suggested that commissions should undertake to emulate it. "Regulation," he wrote, "if it is to be a worthy substitute for competition, must similarly be able continuously to make it impossible for a public utility to charge prices higher than it could charge if an efficient and economic competitor could reasonably be expected to enter the field and capture the market." *20th Annual Report of the Federal Power Commission* (1940), p. 13. As a means toward the accomplishment of this objective, Mr. Olds has looked sympathetically on the use of Tennessee Valley Authority rates and other public-plant rates as "yardstick rates."

Incomplete as is the foregoing summary of the major implications of a purely competitive-price standard of public utility rate making, it should suffice to indicate what drastic changes in the established principles of rate regulation would be called for by any thoroughgoing attempt to embody the standard in practice. Certainly the standard does not comport with an original-cost or net-investment basis of rate control. But neither does it comport with the use of a fair-value or replacement-cost rate base in any familiar or legally accepted sense of these terms. The popular assumption that a strictly competitive price is a price equal to replacement cost must be rejected, even as a rough approximation.

But what about a possible contention that all of our orthodox systems of regulation, whether of the original-cost or of the replacement-cost variety, should be discarded in favor of a scheme of rate control designed to simulate the forces of a competitive market? Such a contention has been made; but it must face formidable objections. In the first place, there is the dilemma presented by the fact that a condition of competitive-price equilibrium is one in which the price is simultaneously equal to average cost and to marginal cost (not to mention long-run and short-run varieties of each of these costs). In the second place, there are the serious practical problems to be faced by a commission if required to dictate how far and how fast a company must go in expanding its plant—a necessity noted in an earlier paragraph. In the third place, there are the difficulties of corporation finance presented by any scheme of rate making yielding the highly variable rates of profit and loss characteristic of competitive industry in a dynamic economy. And in the fourth place, there are the problems that would be faced by consumers of public utility services in adapting themselves to the frequent and rapid changes in rates imposed by competitive responses to changes in current demand and supply.

What these difficulties suggest is that the very characteristics of a public utility business which rule out reliance on actual competition as an automatic price regulator also rule out attempts closely to emulate the behavior of competition in the control of monopoly prices. Indeed, so far as concerns pure or strict competition, which is the standard now under review, modern economists seem to be in general agreement that this "atomistic" type of competitive behavior is not even applicable to the large industrial companies. Here, the competition which must serve as an alternative to regulation or to public ownership is that of a mixed type, which Professor John Maurice Clark has called "workable competition." [11]

THE ALTERNATIVE STANDARD OF "WORKABLE" COMPETITION

Mindful of the serious objections to a competitive-price standard of rate control when defined as a standard of strict or pure competition, we may now turn to the alternative standard of "realistic" or "workable" competition—the type of competition that prevails in real life and that characterizes industries which, because of their size and their relatively heavy capital investments, would seem most nearly comparable to the large public utility companies. As economists have pointed out, competition of this nature is far from "pure," since all large industrial companies possess important attributes of monopoly status.

There is at least a fair prospect that, at some future time—say within the next two decades—standards of socially acceptable "workable competition," covering, among other things, rules of competitive price determination, may have been developed to the stage at which they can serve, with important qualifications, as norms of public service regulation. This stage, however, has not yet been reached, nor does its attainment appear to be just around the corner. There are three related reasons for this cautious conclusion.

In the first place, too little is known today as to the nature of price determination by unregulated industrial companies. It is generally agreed that the "administered prices" of large-scale in-

[11] "Toward a Concept of Workable Competition," 30 *American Economic Review* 241–256 (1940). Paradoxical as it may seem, there is good reason to contend that, both with the public utilities and with heavy industry, a closer approach to strictly competitive price determination could be attained under outright public ownership than under private ownership. Indeed, one school of socialists, the so-called "market socialists," has defended government ownership as making possible the realization of a system of "optimum prices" similar to that which economists have associated with pure competition. See, e.g., A. P. Lerner, *The Economics of Control*, Chap. 7. These contentions, however, involve a dubious assumption: that the ideology of a socialist state and the attitudes of the aggressive types of people who would probably control such a state would be friendly to the principle of consumer sovereignty.

dustry are far less volatile and far less responsive to the forces of short-run supply and demand than would be their behavior under pure competition. But this is a negative conclusion; as to the positive factors in price determination, the subject remains highly controversial.

In the second place, enough is known about modern industrial price policies to belie the assumption that these policies can be reflected by the adoption of any simple, feasibly administered, rule of rate making such as the rule that rates should be based on replacement cost of service. Indeed, these policies do not conform to any single theory of price determination, coordinate with pricing under pure competition. They are the outcome of a whole range of inter-firm relationships intermediate between strict competition and strict monopoly. When modern economists, in attempting to rationalize the price strategy of "competition among the few," are led into an elaborate mathematical analysis called "the theory of games," [12] their findings do not offer very promising material for decisions in rate cases!

And in the third place, since the competition of the type supposed to govern unregulated industrial pricing has no claim for recognition as resulting in the socially optimum prices, emulation on the part of a regulating commission would be of doubtful wisdom even if a fair job of mimicry were feasible.[13] One must remember that the attempts by current economists to develop standards of workable competition for the purpose of antitrust law administration are not attempts to create standards of optimum pricing. On the contrary, they are attempts to secure types of com-

[12] John Von Neumann and Oskar Morgenstern, *The Theory of Games* (Princeton, 1944); J. D. Williams, *The Compleat Strategyst* (New York, 1954). The different price policies prevailing in different types of unregulated industry are presented and compared in Professor Walton Hamilton's book, *Price and Price Policies* (New York, 1938). In his *Managerial Economics* (New York, 1951), pp. 400–401, Professor Joel Dean notes important differences in price policies, not just among different companies or industries but even in the same company with different products. He cites the pricing of the various DuPont products as a conspicuous example. The highly controversial nature of the theory of imperfect or impure forms of competition is illustrated in the discussion of "Concepts of Competition and Monopoly" by Messrs. Clark, Weintraub, Machlup, Gordon, and Ackley at the Dec., 1954, annual meeting of the American Economic Association, published in 45 *American Economic Review, Proceedings* 450–490 (May, 1955).

[13] On the other hand, as long as nonutility prices fail to represent *pure* competitive prices, the fixation of public utility rates at such prices could not be claimed to yield optimum results.

petitive pricing good enough to render price control unnecessary.

Since the competitive-price standard of rate regulation has so often been identified with the acceptance of a replacement-cost or "fair-value" principle of rate control, one may raise the question to what extent the types of competition characteristic of large-scale industrial companies have actually brought prices into rough correspondence with current costs of production plus a normal rate of profit on the depreciated replacement costs of plant and equipment. This question is unanswerable in the absence of wide-scale and careful appraisals of industrial plant and equipment comparable to the tremendously expensive "physical valuations" of the American railroads made by the Interstate Commerce Commission under the Valuation Act of 1913. I think it almost certain, however, that the correspondence would not be close.[14]

Lest the reader of this chapter gain the impression that it is intended to deny the relevance of any tests of reasonable rates derived from the theory or the behavior of competitive prices, let me state my conviction that no such conclusion would be warranted. On the contrary, a study of price behavior both under assumed conditions of pure competition and under actual conditions of mixed competition is essential to the development of sound principles

[14] During the years since the Second World War, prior to the time of the recent stock-market boom, the stocks of many of the best-known industrial companies sold at market prices below their book values, values in turn presumably well below depreciated replacement costs. The steel industry offers a conspicuous example. In testimony before the Senate Banking and Currency Committee in 1955, Mr. Benjamin F. Fairless, chairman of the United States Steel Corporation, was reported to have stated that the current cost of building fully integrated steel-plant capacity from mines to finished product was on the order of $300 per ton, whereas the investor valuation of the plants, as measured by current security prices, was only $56 per ton for the ten largest steel companies, on the average. In its 1954 Annual Report to Stockholders, the Marquette Cement Manufacturing Company stated that, in 1953, it had earned 9.6 per cent on its "original-cost value" but that these earnings represented a return of only 3.6 per cent on estimated reproduction cost (after adjustments for additional depreciation charges on this higher cost). No doubt these and other examples of substandard returns based on replacement-cost tests could be matched by examples of superstandard returns.

The Feb., 1955, issue of *The Exchange*, a monthly publication of the New York Stock Exchange, reported that a study of 1,053 listed common stocks disclosed that 42 per cent were selling at less than their latest available book values. At the extremes among the separately noted industrial stocks, Armour and Company common was selling at 68 per cent below book value, whereas International Business Machines common was selling at 588 per cent above book value.

of utility rate control. Not only that: any good program of public utility rate making must go a certain distance in accepting competitive-price principles as guides to monopoly pricing. For rate regulation must necessarily try to accomplish the major objectives that unregulated competition is designed to accomplish; and the similarity of purpose calls for a considerable degree of similarity of price behavior.

Regulation, then, as I conceive it, is indeed a substitute for competition; and it is even a partly imitative substitute. But so is a Diesel locomotive a partly imitative substitute for a steam locomotive, and so is a telephone message a partly imitative substitute for a telegraph message. What I am trying to emphasize by these crude analogies is that the very nature of a monopolistic public utility is such as to preclude an attempt to make the emulation of competition very close. The fact, for example, that theories of pure competition leave no room for rate discrimination, while suggesting a reason for viewing the practice with skepticism, does not prove that discrimination should be outlawed. And a similar statement would apply alike to the use of an original-cost or a fair-value rate base, *neither* of which is defensible under the theory or practice of competitive pricing.

This chapter has been written under the assumption that the utility subject to regulation enjoys a monopoly, so that any emulation of competitive-price behavior would have to be imposed by governmental authority or adopted as a matter of policy. But this assumption is never strictly valid; and in the field of intercity transport, the degree of railroad monopoly has now become so limited because of road, water, and air competition, that the acceptance of a competitive-price standard of rate control, in some sense of competition, would cease to be the acceptance of a mere make-believe. While the complete abandonment of rate regulation is even here out of the question, the development of new and less rigid standards of rate control seems necessary. In this development, more is to be said for standards suggested by modern ideas of "workable competition" than can be claimed for such standards with the more nearly monopolized utility companies.

So far as concerns the electric power utilities, competition in the sense of rate making by a comparison of the performance of other utility enterprises, including public "yardstick" plants, has been favored by spokesmen for consumer interests. This is not competition as the term is used in economics; but it has promising possibilities for limited and cautious use, and both the promises and the limitations will be noted in Chapter XV, on the fair rate of return.

VII

SOCIAL PRINCIPLES OF RATE MAKING

Despite the failure of the familiar rules of public utility regulation to result in the same rates that might be expected to emerge "automatically" under actual competition, this failure does not necessarily imply a fundamental difference between the objectives of rate regulation and the recognized functions of a competitive price. In large measure, at least, the different results are imposed by technical obstacles in the way of any attempt to compel natural monopolies to behave contrary to their nature.[1] Regulation can still be regarded as a substitute for competition—probably as an inferior substitute.

But the statement that regulation is a substitute for competition would be accepted only with qualifications by any writers aware of its full implications, whereas it would be rejected sharply by a minority of writers on the ground that "public policy," and not merely technological or administrative difficulties, justifies deliberate departures from "commercial" standards of reasonable utility rates.[2] Both the qualifications and the wholesale rejection are based

[1] But regulation is deterred by notions of *fair* prices and *fair* profits from going even as far as technical difficulties would permit it to go in emulating the somewhat ruthless forces of competition.

[2] For a strong defense of this minority position, see the article by Professor Horace M. Gray entitled "The Passing of the Public Utility Concept," noted on pp. 24–25, *supra*. A similar point of view was expressed by Mr. Louis P. Goldberg, former member of the New York City Council, in a letter to the New York *Times* opposing further increases in subway fares designed to make the riders pay the full costs of transit. *Times*, Feb. 8, 1952. Subway service, he contended, is a "social service"—even more completely so than education, health, housing, libraries, etc. The costs of supplying this service, he concluded, should therefore be apportioned on social principles.

I do not include among the advocates of "social" rate making those economists who contend that public utility rates should be set at *marginal* costs even if the resulting revenues would fail to cover total costs (see Chap. XX). For these econoon a variety of reasons often said to rest on "social" principles of rate making rather than on "economic" principles. Elsewhere I have questioned the validity of such an antithesis between the adjective "economic" and the adjective "social." [3] But we may here ignore this verbal issue in an effort to discover the intended meaning of, and the reasons for, the distinction.

THE MEANING OF SO-CALLED "SOCIAL" PRINCIPLES OF RATE MAKING

Earlier chapters have cited a number of examples of "social" principles of rate making, and other examples will be noted presently. Obviously, the term is used loosely and in a variety of senses. By and large, however, it refers to any policy of rate control designed to make the supply of utility services responsive to social needs and social costs, and rejecting as even tolerable measures of these needs and these costs the prices that consumers are able and willing to pay for the services and the money costs that the enterprise must incur in their production.[4] An extreme form of this policy is that which views the welfare of the nation as an end in itself rather than as an expression for the welfare of the people who compose the nation. But, at least in America and Western Europe, such a point of view is not typical even of those who lay most stress on the distinctions between money values and social values.

A study of the different statutes setting forth criteria of rate-making policy, together with a study of the rate cases coming before public service commissions and courts, would reveal many deliberate departures from cost-price standards based on considerations often called "social," although critics might be unkind enough to call them "political." Most of these departures are defended on either or both of two different grounds: on the ground of "ability to pay," and on the ground of "diffusion of community benefits."

mists accept the logic of the principle that competitive prices are optimum prices. Their heresy is not based on those distinctions between money values and social values implicit in a "social" theory of public utility rates. I have emphasized this point in an earlier paper: "Major Controversies as to the Criteria of Reasonable Public Utility Rates," 31 *American Economic Review, Proceedings* 379–389 (1941).

[3] Pp. 31–33, *supra*.

[4] See Hans Staudinger, "Social Rates in Electricity," *Social Research*, Aug., 1936, pp. 259–281; also his "Planning in Electricity," *Social Research*, Nov., 1937, pp. 417–439. But many of the principles cited by Staudinger as examples of social rate making seem to me to be justified on sound "business" grounds.

As a rule, the two grounds are merged in discussions of the actual practice of rate making. But they may be distinguished here for purposes of analysis.

THE ABILITY-TO-PAY PRINCIPLE

The "ability-to-pay" principle [5] is, of course, a transfer of a familiar canon of taxation to the realm of fair pricing. It refers to the contention that the rates of charge for public utility services should depend, in part, on the personal-income status of the consumers. This contention has had its most widespread influence on the rate structure rather than on the entire rate level of a public utility enterprise. But the practical difficulties in the administration of rate schedules which impose higher rates on rich people than on poor people, combined with a wholesome tradition against "personal discrimination," have sometimes led to the acceptance of below-cost rate levels, available alike to rich and poor consumers, and defended on the ground that the service is of a general type urgently needed by persons of low income. This defense was made for the long delay on the part of the City of New York in raising the subway fare above 5¢ and is still made as one reason against any attempt to make the subway system self-sustaining by going above the present 15¢ fare. As to rate *differentials* based on ability-to-pay factors, one may note the special railroad passenger fares favoring deserving persons of reputedly low income (for example, ministers of the gospel); the rule on the Paris Metro permitting wounded veterans and parents of more than one child to ride at special, low fares; and, in some American jurisdictions, the special electric rates for charitable establishments, hospitals, and public housing developments.[6] Among the electric and gas utilities, the

[5] An ability-to-pay principle of rate making should not be confused with a value-of-the-service principle. To be sure, both principles involve forms of price discrimination. But under the former principle, lower rates for the same kind of service should be charged to individuals of lower income regardless of the question whether or not the lower income corresponds to a higher "price elasticity of demand" for the service; whereas, under the latter principle, relative incomes of different classes of customers are taken into account only for their possible bearing on relative elasticities of demand. Indeed, since wealthy consumers may have feasible alternatives not available to poorer consumers, the prices that they could be made to pay for a utility service might well be even lower than the prices that could be imposed on poorer consumers.

[6] The City of New York, which at first opposed a petition by the Consolidated Edison Company asking leave to withdraw its special low-rate classifications for gas and electricity supplied to public housing projects, was reported to have

tendency of commissions to hold the charge for very small rates of consumption to amounts that fail to cover even directly traceable costs has been defended in part on the assertion, denied by company spokesmen, that small customers are typically poor customers.[7]

THE DIFFUSION-OF-BENEFITS PRINCIPLE

Taken by itself, the ability-to-pay principle of rate making rests merely on the contention (a) that public utility services are essentials rather than luxuries and (b) that persons of low income should not be deprived of essentials by any inability to pay the full costs of rendition. But what may be called the "diffusion-of-benefit" principle rests on a different rationale. According to this principle, the benefits derived by the community from public utility service are by no means limited to those persons who pay for the service either directly as consumers or indirectly as the purchasers of products made by the aid of their services. On the contrary, encouragement of full use of the service is in the interest of the entire community or of the entire nation. Moreover, the maximum community benefits are by no means necessarily secured by sale of different types and amounts of service at relative money costs. Some kinds of service may properly be sold at less than cost, and other kinds at more than cost, for the purpose of attaining social benefits or avoiding social costs not attainable under the principle of "service at cost" in an ordinary sense.

Diffusion-of-benefit arguments for breaches of a cost-price system of rate making are perhaps more frequently advanced in the field of transportation. Thus, in New York City and other metropolitan areas, the operation of the public transit systems on a subsidized basis has been defended partly as a means of relieving congestion of street traffic by underloaded private automobiles. And thus, rapid-transit fares that disregard distance of travel have been defended as a means of encouraging decentralization of population. A similar argument has been made in support of the establishment of uniform, "blanket" electric rates over wide areas of an entire

discontinued its opposition. New York *Times*, March 12, 1956. But in a case, still pending as this footnote is written, in which the Consolidated Edison Company has sought leave from the Public Service Commission to abandon the practice of "conjunctional billing" of adjacent buildings held in common ownership, strong opposition has been forthcoming from the New York City Housing Authority.

[7] See Hubert Havlik, *Service Charges in Gas and Electric Rates* (New York, 1938), Chap. 5.

state or region. Related to rate policies of this nature has been the tendency of the Interstate Commerce Commission to take intermediate positions between one establishing railroad freight-rate relationships which preserve for nearer sources of market supply the natural advantages of lower transport costs, and one designed to put the potentially competing sources more nearly on a par[8]—as, for example, with citrus fruits from Florida and California to the Northeastern markets. In a somewhat similar category belongs the same Commission's policy, much criticized by the railroads and by some economists, of forbidding railroads to make special rate reductions to meet road or water competition beyond whatever limited reductions will permit both types of carriers to maintain a "fair share" of the business—a noncompetitive notion of fair competition![9]

Population-decentralization or industry-decentralization arguments for deviations from cost standards have often been associated with national-defense arguments, which have also been accepted as reasons for special subsidies (the merchant marine, the airlines, the early railroad land grants, etc.), justified on the ground that the national defense requires the construction of plants and the continuous operation of services that could not or should not be made to pay their full way by charges for peacetime consumption. Far less justifiable from the standpoint of an economist has been the use of national-defense arguments in support of requirements, imposed especially on railroads, to maintain noncost-recovering services, the burden of the resulting deficits falling either on the stockholders or else on the users of those other services that can be made to stand the loss. This practice amounts to a distorted use of social principles of rate making and would be criticized by many of the supporters of these principles.[10]

Other benefit-diffusion arguments have had more or less influ-

[8] I. L. Sharfman, *The Interstate Commerce Commission*, Vol. III B (New York, 1936), pp. 656–693.

[9] See "Problems of the Railroads," *Report of the Subcommittee on Surface Transportation of the Committee on Interstate and Foreign Commerce*, April 30, 1958. U. S. Government Printing Office, 1958. The Transportation Act of 1958 contains a provision adverse to the above-noted policy.

[10] "Common carriers cannot be expected to recover from peacetime freight revenues the cost of maintaining their equipment or facilities in readiness for defense needs; this should be financed by government from general taxation for defense, and not borne by carriers or shippers." Statement by D. E. G. Plowman, Vice President, Traffic, United States Steel Corporation, quoted by *Railway Age*, March 7, 1955, p. 10.

ence on American rate-making policies. Among these we may note the Interstate Commerce Commission's reluctance to let railroads quote cost-justified discounts for full-trainload shipments—a reluctance based on a desire to favor smaller-scale industrial companies; the familiar objections, based on health and sanitation grounds, against metered charges for city water supply; and a number of plausible arguments in favor of rates designed to encourage the use of electricity rather than alternative forms of energy,[11] one such argument running in terms of relative fire hazards. The more ardent supporters of low-priced public power, both in this country and in England, have gone to great lengths in their enthusiasm for the bountiful use of electricity, regarding the growth in power consumption as the prime mark of industrial progress and of modern living.[12]

For obvious reasons, the most unrestrained advocates of social theories of rate making are not to be found among the representatives of the private utility companies. Yet even these representatives sometimes adduce social-benefit arguments on behalf of the rate-making policies which they favor. At a conference on telephone rates which I attended several years ago, an official of the Bell System used such an argument in defense of the System's policy of charging rates higher in larger cities than in smaller communities, even beyond the point at which this policy could be justified strictly on grounds of relative costs. The benefit conferred by the

[11] See Hubert Havlik, *Service Charges in Gas and Electric Rates*, pp. 115–119, referring to the "public policy" that all buildings in a populated district should have electric service. In the first edition of his *Electrical Engineering Economics* (London, 1928), pp. 195–196, D. J. Bolton wrote: "The actual physical need for electricity, with its absence from fumes, etc., is greatest in the dark and overcrowded rooms of those who are at present least able to afford it."

[12] In an article on "The Price of Fuel," 6 *N.S. Oxford Economic Papers* 226–242 (1954), D. L. Munby refers to a memorandum by the British Electricity Authority ending "with a paean of praise of electricity as 'one of the most powerful tools yet devised by man to raise his standard of life.'" Munby states that, while the same Authority defended its rate-making practices as in harmony with the principle of consumer choice, the British Gas Council denied the existence of such a harmony in the relationship between rates for electricity and rates for gas.

In recent public statements, Mr. Philip Sporn, one of America's outstanding private-utility operators, has denied that the industrial progress of a nation should be identified with the development of cheap electric power. See his "Observations on Private Versus Public Power," 53 *Public Utilities Fortnightly* 717–733 (1954). But even if the cheap-power enthusiasts are right, what is important is that strenuous efforts be made to minimize the costs of producing and distributing electricity, not that the sale prices be held below costs by tax-financed subsidies.

installation of any one telephone station, he noted, is not limited to the particular subscriber. Indeed, the interest of the whole community demands the widest feasible access of families and of businesses to the interchange of messages. This objective, he urged, can best be attained by a system of differential rates of charge that do not place too much emphasis on relative costs of service.[13]

THE LIMITED RECOGNITION OF "SOCIAL" PRINCIPLES OF PUBLIC UTILITY RATES

Many other examples of "social" principles of rate making could be found by an extensive study of the rate cases. Transportation rates, especially, would provide a rich field for exploration. Yet I think it fair to say, as was said in the introductory chapter of this book, that American rate making has adhered in the main to the standard of service at cost, and that even most of the departures therefrom have been due to administrative, historical, and business reasons rather than to "social" reasons.[14] Indeed, if the social considerations were to become dominant, the enterprises to which they apply would cease to be public utilities in the accepted sense of the term. They would then become "socialized," like the public schools, the tax-financed or endowed universities, and (to a greater degree) the police, the courts, the navy, and the city-street departments.

[13] From the standpoint of the private telephone companies, this point of view has dangerous implications. For it seems to justify subsidized telephone service, and arguments for subsidies are almost sure to be associated with arguments for public ownership.

[14] Pp. 22–24, *supra*. The same general statement would apply to the rate-making practices of the nationalized British utilities. See J. F. Sleeman, *British Public Utilities* (London, 1953), who cites, as exceptions, numerous examples of "social" rate making. In a 1956 report on electric rates by a government committee, the British Electricity Authority was criticized for deviations from "business principles" including acceptance of "national-policy" reasons for its decision to carry insurance with British insurance companies instead of practicing self-insurance. *Report of the Committee of Inquiry into the Electricity Supply Industry*, Jan., 1956, Cmd. 9672, pp. 7, 57, 96–97. The Committee declared that, if "political" objectives are to govern electric-power policy, these objectives are the responsibility of the Ministry and of the Parliament, not of the Authority. It insisted that, if there were any need for a rural-electrification subsidy (which it doubted), the subsidy should be provided by Parliamentary grant, not by charges against non-rural consumers. Professor R. H. Coase notes the different philosophy of the earlier Committee on Land Utilization in Rural Areas (the "Scott Committee"), which insisted that the supply of electricity is an "essential service" and that it should be available at the same price to country people as to city people. 15 *The Manchester School* 139 (1947).

But why should not the public utility services be socialized in the sense just mentioned, as has been urged by a minority of writers? The short answer is that the reasons which justify their price regulation are not reasons which justify their socialization.[15] But a brief exposition of this answer is in order. For this purpose, it will be convenient to discuss separately the ability-to-pay factor in social-pricing theory, and the benefit-diffusion factor, even though in practice the two factors are often intermixed.

CRITIQUE OF THE ABILITY-TO-PAY PRINCIPLE

Taken by itself, the ability-to-pay argument for departures from a cost-price or competitive-price principle of utility rates stands on the same footing as would an argument for the differential pricing of *all* commodities and services of comparable necessity. What, then, are the reasons for its general rejection, even by those who support the analogous principle of taxation?

Aside from formidable difficulties of administration, the objections are twofold. In the first place, to the extent that the ability principle of pricing were to accomplish its purpose, to that extent it would convert unequal distributions of cash income into equal distributions of real income—a conversion that could not feasibly be confined to those cash-income differentials deemed undeserved or otherwise socially indefensible. But in the second place, if public policy favors a reduction in income discrepancies, this objective can be accomplished by alternative instruments of social control, including progressive taxation, social security, and free public education, more feasibly and less harmfully than by a system of discriminatory prices. In short, the more promising attack on the maldistribution of cash incomes lies in a more direct attack on the maldistribution or on its causes, not in the administration of antidotes.[16]

[15] This position is taken by Professor I. L. Sharfman with respect to transportation rates. See his *The Interstate Commerce Commission*, Vol. III B (New York, 1936), pp. 690–693. Sharfman insists that transportation costs should enter the prices of commodities and should motivate the location of industries just as much as any other production costs.

[16] This point of view, familiar to modern welfare economics and modern tax theory, is developed at length by A. P. Lerner in his *Economics of Control* (New York, 1947), especially Chap. 4. Lerner stresses the point that if the prices of commodities and services are made to deviate upward and downward from their (marginal) costs, in an effort to offset differences in individual incomes, the economic organization of society will lose efficiency because individuals will be under an inducement to buy things that are offered to them at below-cost prices, even though they would prefer other, higher-priced things that could be produced at no higher social costs.

But some recent economists have suggested that the limited power of a state to effect a direct redistribution of income by taxation—a limit made serious by heavy revenue requirements of a modern state—may justify a partial resort to the price system to take care of the underprivileged. See, e.g., Marcel Boiteux, 58 *Revue générale de l'électricité* 321 (1949). In his *Welfare Economics and the Theory of the State* (Cambridge, Mass., 1952), p. 127, Professor William J. Baumol cites several references on the question whether rationing of incomes is better than rationing of commodities.

To be sure, the above-noted objections to price discrimination in favor of low-income recipients have not deterred modern capitalism from putting it into limited application in public housing, in hospital charges, in medical fees, in educational scholarships, and elsewhere. But in most of these situations, the benefit-diffusion consideration has also been prominent. With public housing there is the further point that rentals constitute a very large fraction of a low-income family budget, unlike the typical situation with public utility services. But if standard rates of charge for these latter services are beyond the means of the occupants of subsidized housing, a persuasive case can be made for the assumption of a part of the charges by the housing authorities rather than for the concession by the utility enterprise of substandard rates, to be offset by surcharges imposed upon other customers.

CRITIQUE OF THE DIFFUSION-OF-BENEFITS PRINCIPLE

Taken alone, the case for the acceptance of ability-to-pay standards of public utility rates is a very weak case save as a jury-rudder expedient under emergency conditions. A far more persuasive case can be made for departures from cost pricing with respect to services, the performance of which serves important community needs in addition to those needs for which it is feasible to exact a price. The extreme examples, of course, are those of government services financed entirely by taxation rather than by sale, and therefore ruled out of the public-utility category by very definition. But intermediate examples can be found inside those enterprises traditionally called public utilities—examples in which a plausible case can be made for relieving the regular consumers from the full payment of those costs not incurred entirely for their benefit. Examples of this possibility have already been cited. But we may add another example: that of a national-defense reason for a rule requiring an electric utility company to maintain, say, a 20 per cent stand-by reserve even if a 10 per cent reserve would be deemed quite adequate for peacetime purposes. Here a forcible argument can be made for a national-defense subsidy sufficient to offset the special, national-defense cost.[17] Such a subsidy would not conflict with the old legal maxim, "Let the beneficiary bear the burden." On the contrary, it would be in harmony with this maxim.

Although social principles of rate making are usually advanced in support of *lower* public utility rates than would otherwise be warranted, the logic of these principles may work also in the other direction. For, as was noted in Chapter IV, the money costs of producing the service—the so-called enterpriser costs—may not cover losses imposed on innocent bystanders.[18] Moreover, the act of supplying service to any given consumer may impose indirect burdens on other consumers. Striking examples of this are traffic congestion on streets and highways and passenger congestion in local buses or subway trains. When any one passenger crowds into a subway train at rush hours, he adds to the misery of the other passengers in addition to becoming a fellow sufferer. Under the logic of a social theory of rate making, under which the rates should cover the social costs, this cost-diffusion factor might be taken into account through the imposition of higher fares than would be warranted on cost principles in the ordinary sense.[19] But popular opinion would not support any such use of the price system to relieve rush-hour congestion.

[17] See Benjamin S. Loeb, "Electric Power Supply and National Security; a Study in Public Policy," Ph.D. Dissertation, typescript, Columbia University, 1959. Reproduced by U.S. Atomic Energy Commission, Washington, D.C.

[18] Referring to Great Britain, D. L. Munby writes: "The recent interim report of the Committee on Air Pollution has estimated that the annual cost of pollution may be more than one hundred million pounds per year, apart from waste of fuel." 6 *N.S. Oxford Economic Papers* 239 (1954), citing Cmd. 9011, pp. 20–21. Compare a lower estimate for an earlier year cited by I. M. D. Little in *The Price of Fuel* (Oxford, 1953), p. 79. On social versus private costs in the development of natural resources, see Joseph L. Fisher, "Natural Resources and Technological Change," 29 *Land Economics* 57–71 (1953).

[19] Here, however, the "social" theory of rates, while justifying a departure from the cost-price principle in its usual sense, is in harmony with a strict competitive-price theory for reasons suggested by Professor Frank H. Knight in a now famous article taking issue with a position once taken by Professor A. C. Pigou in the early editions of *The Economics of Welfare*. That is to say, if transit could be, and were, supplied by unregulated companies under conditions of strict competition, their profit-maximizing objectives would lead them to charge differential fares that would preclude any excessive rush-hour use caused by the failure of each passenger to feel the hardship that his presence imposes on all other passengers. See Knight, "Some Fallacies in the Interpretation of Social Cost," 38 *Quarterly Journal of Economics* 582–606 (1923/24).

Neither the diffusion-of-benefits argument for deviations from ordinary cost pricing, nor its counterpart, the diffusion-of-costs argument, can be ruled out on principle in public utility rate making, as can the simple ability-to-pay argument except as a makeshift device. To what extent, however, such deviations are justified in actual practice is quite another question. The reasons for caution and skepticism in use are indeed forcible. First, there is the extreme difficulty of prophesying and measuring indirect social benefits and social costs. Secondly, and in the absence of objective tests, there is the certainty that exaggerated claims of community benefits will be put forward by pressure groups. And thirdly, there is the question whether the indirect benefits from the production of any given public utility service will be greater than those that would result from the alternative production of other commodities and services offered for sale at market prices that do not take social benefits into account. Unless this question can be answered in the affirmative, a reduction of utility rates only, made in order to allow for social benefits, would result in a distortion between these rates and other prices.[20]

If the tone of this chapter is somewhat less than enthusiastic for those views of rate-making policy said to be based on social principles, the coolness is not due to a belief that these views have no place in the theory or practice of public utility rate making. It is due, rather, to a conviction that those services now called public utility services belong in that great class of economic products, including both commodities and services, that can best be offered for sale instead of being supplied without charge, and that can typically best be sold on the general principle of service at cost rather than at prices designed by a legislature or public service commission to accomplish some specific objective deemed by it to be in the public welfare.[21] This conviction is supported by a recognition of the greater importance of socialized services in *other* sectors of a modern economy. Even aside from the terrific burdens

[20] In his *Welfare Economics*, p. 32, William J. Baumol makes the related point that, assuming a given level of output, the divergence between marginal social cost and marginal private cost need not cause competition to result in a non-optimum allocation of resources so long as the divergence is of equal strength in all industries.

[21] "The Court never before has confided to our regulatory body the reshaping of our national economy." Justice Jackson, dissenting, New York v. United States, 331 U.S. 284, 362 (1947).

of national defense, the Federal, state, and local governments will be called upon to devote increasing shares of the total national income to the production of services, such as those in the fields of health, education, and recreation, that cannot feasibly be distributed by the mechanism of the price system. In order to finance these needs for truly collective services, the tax system will be put under heavy strain, as indeed it is put today. Only for compelling reasons should the strain be enhanced by the inclusion in governmental budgets of vast appropriations for subsidized utility and transportation services.

But the viewpoint just set forth merely expresses a general attitude, which is that of a *rebuttable presumption* in favor of so-called "business principles" of rate making.[22] Even if modern rate-making policy continues to accept this presumption in the future, as it has in the past, it still faces the task of setting up conditions for successful rebuttal. This constitutes one of the most formidable assignments of modern welfare economics—that of developing principles of social valuation and of social-cost determination.

[22] This is a very different attitude from that of those extremely "conservative" writers who appear to treat the presumption as conclusive. Thus a Task Force of the "Second Hoover Commission," in its report on Federal power policy, criticized the Federal administration for having used water resources and power-development projects, "which should be undertaken exclusively for economic purposes, to accomplish indirect social and political ends." Commission on Organization of the Executive Branch of the Government (1953–55), *Task Force Report on Water Resources and Power,* Vol. I (Washington, D.C., 1955), p. 13.

VIII

FAIRNESS VERSUS FUNCTIONAL EFFICIENCY AS OBJECTIVES OF RATE-MAKING POLICY

Cutting right across that classification of rate-making criteria suggested by the titles of the last four chapters—cost of service, value of service, competitive price, and "social" principles—is a vitally important distinction between two general points of view from which a choice may be made in favor of any particular version of any one criterion. Looked at from the first point of view, the choice should depend on considerations of "fairness" or "equity" or "justice"—fairness as between investors and consumers when the general *level* of rates is at issue; fairness as among the different classes of consumers when the rate *relationships* are under inquiry. Looked at from the second point of view, the choice should depend on a variety of "practical" or "economic" considerations only indirectly related to the equities of the specific parties—considerations perhaps best characterized as those of functional efficiency.[1]

Thus, the reasonableness of a company's request for approval of an across-the-board increase in its rate schedules may be judged by reference to the question whether or not the increase is called for in simple fairness to the corporate investors, who have committed their capital to the enterprise in reliance on an opportunity to

[1] The first point of view is said to be derived from the medieval conceptions of a "just price," *justum pretium.* See the article "Just Price," by Edgar Salin, in the *Encyclopaedia of the Social Sciences,* Vol. 8 (New York, 1932). He writes: "The just price, on the other hand, as a conception and as a doctrine is basically ethical rather than economic." While not completely devoid of economic content, "it recognizes no validity for economic activity as such nor independent economic norms. Its law is derived from theological doctrines and from the philosophy of mediaeval class society."

enjoy a fair rate of return. But it may also be judged by reference to the question whether or not an enhancement in earning power, fair or unfair, is required in order to maintain corporate credit and hence in order to enable the company to supply adequate service. And thus, the question whether or to what degree rates for off-peak electric service should be lower than rates for service supplied partly on the system peak can be viewed as a problem of *equitable* cost apportionment between the two classes of consumers. But it can also be viewed as a problem of establishing whatever rate differentials are best designed to stimulate the optimum use of plant capacity as well as best designed to avoid the necessity of an uneconomical expansion of this capacity—a functional-efficiency problem.

In railroad and public utility regulation, most contested rate cases are argued by the opposing parties from both points of view. But many of the opinions of courts and commissions—the earlier opinions more so than some of the recent ones—might seem to support a popular assumption that the major concern of rate regulation is with the *fairness* of the rates. Indeed, fairness and reasonableness are often used as interchangeable terms. Forty years ago, a writer with an engineering background well reflected not only this use of language but also this implied mode of thinking when he gave to his entire book on public utility regulation the title, *What Is Fair?* [2]

Today, despite the persistent use of the words "fair" and "reasonable" as mere synonyms, no responsible writer or public service commissioner would attempt to develop or appraise rules for the determination of reasonable rates by sole reference to standards of fairness or equity. Yet there remain important differences in the relative emphasis placed by different persons on fairness considerations as compared to other considerations, together with even more important differences in the accepted standards of fairness. By and large, expert opinion has tended to place more and more emphasis on "practical" or "efficiency" factors, restricting the fairness issues to such problems as those concerned with retroactive rules of rate making.[3]

[2] William G. Raymond, *What Is Fair?—A Study of Some Problems of Public Utility Regulation* (New York, 1918).

[3] My colleague Professor Ernest L. Williams calls my attention to the shift in the Interstate Commerce Act from a standard of reasonable rate levels expressed in terms of *fairness* (Transportation Act of 1920) to a standard which emphasizes the adequacy of the rates from the standpoint of maintaining an efficient railroad system (Act of 1933).

The academic economists have gone farthest in this direction, some of them taking the position that issues of fairness are beyond their professional competence and concern.[4] But even courts and commissions, which are naturally highly responsive to popular or traditional ideas of equity among the parties to a rate case, have shown a tendency, though a lagging one, to shift their emphasis. Here, as was noted in Chapter II, the lead was taken by the Supreme Court, which, in 1944, abandoned its earlier, legalistic test of fair rates in favor of the acceptance of a functional approach.

At the risk of being subject to the prejudices of my profession, I am convinced that the modern tendency to view fairness criteria of reasonable rates as secondary criteria, to be accepted primarily as constraints on the application of the so-called economic criteria, is a mark of progress in the development of rate-making policies designed to serve the public interest. But this means merely that fairness issues should be kept in their place. It does not mean that they should be cavalierly dismissed or even belittled. What these issues are, and what part they should play in the development of rate-making policies, are the questions discussed in the present chapter.

[4] For example, Ralph K. Davidson, whose monograph on rate discrimination insists that it is concerned solely with "economic" criteria and not with fairness. *Price Discrimination in Selling Gas and Electricity* (Baltimore, 1955), p. 111. Another economist, reviewing Davidson's book, comments adversely on lawyers "vainly seeking equity where efficiency should have been the objective." H. S. Houthakker, 46 *American Economic Review* 734–735 (1956).

The fairness of public utility rate levels was much disputed during the great depression of the 1930s, some writers insisting and others denying that, on grounds of equity, these rates should be reduced in harmony with the reduction in personal incomes and in other prices. While favoring flexibility, J. K. Galbraith, now Professor of Economics at Harvard University, took the position, characteristic of economists, that "fairness" was not the main issue. "No longer," he declared, "is public policy toward monopoly power concerned merely with fair prices. . . . It is also concerned with *harmonious* prices and *harmonious* price changes; the problem of prices which do not intensify and prolong fluctuations in the economy." "Monopoly Power and Price Rigidities," 50 *Quarterly Journal of Economics* 474 (1936).

Some modern "welfare economists," associating or identifying arguments about equity with arguments about income-distributive justice, have denied that the issues are subject to rational solution on the ground that they involve a hopeless attempt to make interpersonal comparisons of satisfactions. See Kenneth E. Boulding's article on "Welfare Economics" in Bernard F. Haley, ed., *A Survey of Contemporary Economics*, Vol. II (Homewood, Ill., 1952), pp. 1–34. But other economists disagree, e.g., A. P. Lerner, *Economics of Control* (New York, 1947), Chap. 3.

THE BABEL OF CONFUSION AS TO WHAT CONSTITUTES "FAIRNESS"

The broad distinction, noted above, between fairness standards and efficiency standards should not be taken to imply the existence of two alternative measures of reasonable rates, the one derived from considerations of fairness, the other derived from considerations of economics or of corporation finance. On the contrary, persons who think in terms of equity or justice are likely to be as hopelessly at odds with one another as they are with persons who think in terms of social efficiency.[5] A major part of the disagreement lies in the association of "fair" treatment of individuals with "equal" treatment. But, in the first place, equality in one respect means inequality in others.[6] And, in the second place, a decision on rates designed to put one set of persons on a par with another set will often make still others the victims of discrimination.

Consider, for example, the fairness aspect of the question whether, in a period of price inflation, permitted rates of return should be raised in such a way as to give utility common stockholders an offsetting increase in money income. Such a raise would put these stockholders more nearly on a par with the holders of stock in many industrial companies. But it would thereby give them an advantage over the recipients of incomes from investments in savings banks, in U.S. savings bonds, in annuities, and in life insurance policies, not to mention incomes from holdings in preferred stock and in limited-dividend housing projects. No wonder that, quite aside from practical considerations of corporation finance, opinions differ as to the fair claims of public utility stockholders.[7]

Consider, again, the fairness of a proposal for uniform electric

[5] "In the nature of their functions, value-symbols and moral injunctions must suffer from logical inconsistencies if they are to be part of working ideologies. If they were qualified to the point where they could be applied literally, they would lose their evocative force." Francis X. Sutton, *et al.*, *The American Business Creed* (Cambridge, Mass., 1956), p. 264.

[6] One is reminded of the comments of Anatole France on the legal obligation of the poor under received ideas of social justice: "Ils y doivent travailler devant la majestueuse égalité des lois, qui interdit au riche comme au pauvre de coucher sous les ponts, de mendier dans les rues et de voler du pain." *Le Lys rouge* (Paris, 1894), pp. 117–118.

[7] Pp. 270–274, *infra*.

rates throughout both urban and rural service areas—a proposal made, let us say, in the face of undeniable evidence that the unit costs of supplying the rural service are very much higher than the unit costs of city service. Here, to be sure, there may be plausible *practical* grounds for rate uniformity if the costs of the rural service do not bulk too large in the total costs of supplying the whole area. But if the question is argued on grounds of fairness among customers, opinions are likely to be widely divided. On the one hand, there is a strong tradition in support of the fairness of rate differentials based on cost differentials.[8] But on the other hand, there is a widely held, conflicting belief in the "inherent fairness" of a rule of equal prices for services regarded as "the same" in some superficial sense and despite marked differences in cost of rendition. This popular preference for rate uniformity beyond the limits justified by the advantages of simple rate structures has been repeatedly noted by current economists, most of whom keenly regret its political appeal. Only under special circumstances can the demand for this spurious equality of treatment properly claim whatever merit can be claimed for ability-to-pay principles of pricing, or for those other "social" principles discussed in the preceding chapter.

Of all of the many problems of rate making that are bedeviled by unresolved disputes about issues of fairness, the one that deserves first rank for frustration is that concerned with the apportionment among different classes of consumers of the demand costs or capacity costs—those costs of service that are regarded as a function of required plant capacity and not of rate of output in kilowatt-hours, cubic feet of gas, ton-miles of traffic, etc. Should the capacity costs be assigned to the different consumers on the basis of system peak responsibility, or of coincidental class demand, or of any one of the other thirty-odd proposed bases of assignment to be found in the literature of rate theory? Here, notions of "fair apportion-

[8] "Man's inborn sense of fairness and equity seems strangely satisfied if he be assured that he is paying for a unit of energy only what it has cost to generate and deliver it." A. C. Marshall and H. A. Snow, "Distribution Costs—Residential Service," reprinted in Samuel Ferguson, *Public Utility Papers* (Hartford, Conn., 1947), I, 354–381 at 355. Compare Professor J. K. Galbraith's remark on farm subsidies: "In the Puritan ethos there is no such thing as a legitimate subsidy. If one must nevertheless be subsidized, how much more seemly to have it out of sight." "Farm Policy: The Current Position," 37 *Journal of Farm Economics* 292–304 at 300 (1955).

ment" are almost sure to conflict with economists' convictions as to the relevant cost allocations. But these notions are themselves neither stable nor uniform, although they reveal a general tendency in favor of a fairly wide spreading out of the costs, as butter would be spread over bread in a well-made sandwich. Awareness of these unresolved conflicts about "fair" cost apportionment has led the British economist Professor W. Arthur Lewis to exclaim that, in rate determination, "equity is the mother of confusion." [9]

THREE DIFFERENT TYPES OF FAIRNESS STANDARDS

What can be done, if not to resolve the confusion to which Professor Lewis refers, at least to determine its sources and to minimize its frustrating influence on the theory and practice of rate making? Perhaps the best way to begin is to ask what "fairness" means when used in the context of a rate case. Just what does a contestant intend to assert, for example, when he opposes any rate or rule of rate making, not on grounds of difficulty of administration or of ineffectiveness in attracting capital or of nonpromotional character, but simply on the ground that it is unfair? Unless one is ready to accept completely the cynic's position that a "fair rate" means whatever rate is in my self-interest,[10] this is no easy question. And the dictionaries are here of little help, since their relevant definitions of fairness merely put the reader into a dizzy merry-go-round of synonyms (equity, justice, etc.).

To be sure, we can go a certain distance toward an answer by noting that a finding that rates are fair, as distinct from a finding that they are otherwise socially acceptable, implies a proper balancing of the relative claims of the interested parties when these parties are viewed, not as mere economic agents or factors of production, but as human beings entitled to respect for their own interests. In

[9] *Overhead Costs* (London, 1951), p. 23.

[10] Referring to the Electricity Consultative Councils in the organization of the nationalized British electric power industry, a recent report by a departmental committee remarks: "They also have to face criticism from the public who, in general, are averse to any changes in electricity tariffs, unless of course it is to their benefit." *Report of the Committee of Inquiry into the Electricity Supply Industry*, Jan., 1956, Cmd. 9672, pp. 104–105. But in Sutton *et al.*, *The American Business Creed*, cited in footnote 5, the authors conclude that a good part of the businessman's notions of "fairness" and "justice" cannot be accounted for as mere reflections of self-interest.

the majority of cases, moreover, we are also correct in associating the fairness issue with the income-distributive effect of the rates and not directly with their producer-incentive or consumer-motivation effects.[11] But we are still uninstructed not only as to tests of a fair income-distributive effect but even as to the very meaning of the requirement that the effect be "fair."

Any attempt to get much further with this mixed problem of semantics, social psychology, folklore, and ethics would go quite beyond the field of economics and even farther beyond the scope of a book on public utility rates. But one point is clearly revealed by a mere study of the rate cases: namely, that there are different conceptions or standards of fairness, only loosely related to one another and often in conflict with each other. Among these standards, three types may be distinguished here because of their relevance to the theory and practice of public utility regulation. They may be called, respectively, (1) good-faith standards, (2) income-distributive standards, and (3) notional-equality standards.[12]

1. GOOD-FAITH STANDARDS

The meaning of "fairness" in business transactions is most clearly definable when referring to a moral obligation, which may also be a legal obligation, to avoid deception and to live up to previous commitments, expressed or implied. If judged by this test alone, any rule of rate making would be fair to investors, whatever its merits or demerits on other grounds, if it conforms to the terms, on the faith of which the investment was originally made—fair no matter how onerous or how profitable these terms may prove to be in the light of hindsight.

In the history of American public utility regulation, the most

[11] But income-distributive aspects of economic policy are not *necessarily* viewed in terms of "fairness" or "justice." They may be viewed, e.g., hedonistically, as a problem of securing that income distribution which will maximize total happiness—viewed in this manner by persons who purport to take no interest in the question whether actions that they approve, as contributing to maximum happiness, are "fair" or "unfair." Or, in the more modern manner, they may be appraised from the standpoint of over-all economic or social effects on community welfare—e.g., from the standpoint of the possible effect of a more nearly equal distribution of income in reducing the severity of business depressions, or in contributing to the elimination of tuberculosis.

[12] In his book on *The Sense of Injustice* (New York, 1949), Edmond N. Cahn notes six popular demands viewed as demands for fairness or justice: equality; recognition of desert; respect for human dignity; conscientious adjudication; confinement of government to its proper functions; and fulfillment of common expectations.

conspicuous example of a line of cases in which this conception of fairness was put to the test (and, incidentally, found wanting) was that presented by the early 5¢ fare franchises granted to the street railways and to the rapid-transit companies. In the heydays of the "street car," operation under these franchises proved highly profitable. But as a result of the rise in prices and wages during and after the First World War, the 5¢ fare first became unprofitable and then ruinous. As might have been expected, the corporate managements made a determined effort to secure relief from these outmoded obligations; and usually the relief was granted, either by the courts whenever they could find the franchise to have been noncontractual in character, or else by obliging state legislatures. In large part, this forgiveness even of contract obligations was justified on the "practical" ground that the companies could not otherwise continue in service. But there can be little doubt that the action was also influenced by appeals to the "injustice" of any attempts to enforce the letter of the early franchises.

The 5¢ fare cases are exceptional in the history of American utility regulation. For the modern law of commission regulation does not predetermine the rates that a company must continue to charge in future years, nor does it even set up a precise formula by which the fairness of these rates shall be redetermined from year to year. But this very lack of a definite understanding as to the criteria of a fair return, or as to the circumstances under which the company may assert a right to the enjoyment of such a return, has given rise to countless disputes between company spokesmen and consumer interests as to the implicit understanding or "reasonable expectation" under which capital was committed to the enterprise. One such dispute concerns the claim, once frequently advanced by public utility representatives, that a retroactive application of a prudent-investment rule of rate making, without compensation for early investments made on the faith of the more generous but much criticized fair-value rule, would be unfair to existing investors. Twenty-five years ago, when the fair-value rule was still held to represent the constitutionally imposed "law of the land," this claim was conceded to have weight even by defenders of a prudent-investment rate base in principle. But the argument has now lost much of its force with the lapse of time and with the adaptation of the stock market to newer philosophies of rate making.

Good-faith standards of fairness have been invoked by consumers no less than by investors in support of rates that would otherwise be deemed indefensible. The appeal is likely to take the form of an insistence by a particular class of customers on the right to the continued enjoyment of low rates which, while originally justified by cost analyses or otherwise, have subsequently been made obsolete by changed conditions including, particularly, changes in load factors or the disappearance of competition. The argument runs to the effect that the consumers were induced to locate their factories, or to abandon their isolated generating plants, or to convert their furnaces from coal burners to gas burners, in contemplation of the low, "promotional" rate and on the faith that this rate would remain in effect for the indefinite future. As a matter of legal doctrine, such an argument has dubious standing in view of the generally accepted principle that public utility rates are subject to revision if and when they become "unreasonable." But in the politics of utility and railroad rate regulation, it is sometimes pressed with enough force to retard for years changes in rate structure otherwise clearly desirable.[13] Indeed, one of the strongest practical objections to the pricing of special classes of service at rates only slightly above immediate incremental costs, even if these rate concessions would be required in order to attract the service, is that the low rates may create a vested interest in their continuance after the growth of demand has brought the incremental costs to a point equal to, or even above, the average costs.[14]

[13] In electric and gas rate making, commissions have sometimes approved a makeshift solution by permitting old customers to continue service at the old rates, new customers being subject to the higher, revised rates. But this action runs against a rival standard of fairness, the generally accepted principle adverse to "personal" discrimination.

[14] Some years ago, a number of manufactured-gas companies found themselves in this position after they had stimulated widespread resort to residential space heating by the establishment of heating rates originally justified because of redundant plant capacity. In railroad rate regulation, a striking example of a similar situation was that of the low "commodity" rates that the transcontinental railroads put into effect for eastbound Pacific Coast lumber, at a time when the balance of railroad traffic was heavily in the westbound direction. Partly, at least, because of the low lumber rates, the balance shifted. But there was a long delay before the railroads succeeded in securing a corrective shift in their rate structures. See Marvin L. Fair and Ernest W. Williams, *Economics of Transportation*, 1st ed. (New York, 1950), pp. 430–433.

2. INCOME-DISTRIBUTIVE STANDARDS

Sometimes supporting, sometimes conflicting with, good-faith or reasonable-expectation standards of fairness are other standards concerned directly with the income-distributive, or income-transfer effect of the rates—with the fairness (rather than with the motivating and restraining efficiency) of the payment for the service due from the consumer and receivable by the producer. This is the effect distinguished in Chapter III as giving rise to one of the four major functions of public utility rates—the income-distribution function. There two rival standards for the effective performance of this function were set forth: the compensation standard, in which the payment is based on an indemnity principle, or at least on some measure of fair payment not too far removed from that of indemnity; and the "ability-to-pay" principle. Both of these principles, frequently combined in indefinite mixtures, have had their influence on rate-making law and on its administration, and each of them has been defended, sometimes as an instrument for the efficient performance of the work of the world, sometimes on grounds of "inherent fairness." The first principle supports a cost-price basis of rate making; the second would support whatever deviations from cost can feasibly be applied in order to minimize the burdens falling on those consumers with the lower incomes. The previous chapter has taken the position, held in common with many other economists, that the compensation principle of rate making is far preferable to an ability-to-pay principle, save under certain emergency conditions. But the other position has considerable popular support.

3. NOTIONAL-EQUALITY STANDARDS

By these standards I refer to a popular tendency, already noted in an earlier paragraph, to assert the fairness of uniform rates for the same type of service despite significant differences in cost of rendition and perhaps, also, in elasticity of demand. Possibly this tendency is really a distorted reflection of an income-distributive standard. But it certainly fails to accord with any of the more general theories of proper income distribution. Instead, it accepts a specious egalitarianism.

One example of the influence of this egalitarianism has already

been noted—the popular support given in this country to uniformity of rates throughout a wide area quite apart from considerations of simple administration and from difficulties in the way of reliable cost allocation. In a report on the electricity supply industry issued in 1956,[15] a British departmental committee refers similarly to contentions by consumers that the nationalized power industry should levy the same charges throughout the country. From this position the Committee dissented, although it qualified its dissent by noting that, with a nationwide grid and with improvements in long-distance transmission, charges may become more nearly uniform even on a cost basis. In an article on "The Price of Fuel" written in 1954, the British economist D. L. Munby insisted on the need to get coal prices away from a false equalization, made in disregard of important cost differences.[16] And in a recent book on British transportation rates, A. M. Milne regrets the existence of notions of fairness favoring the acceptance of "postal tariffs" for railroads, or at least of uniform mileage charges regardless of important cost differentials.[17] In American railroad rate regulation, Professor Sharfman and others have noted the conflict within the Interstate Commerce Commission itself between concepts of "equal treatment" in terms of formal rate uniformity despite cost differences, and of "equal treatment" in the different sense of uniform adherence to cost standards.[18]

From the standpoint of public utility rate theory, the most frustrating of all of these egalitarian notions is the one which tends to identify a "fair" charge with a charge related only to the cus-

[15] Cited in footnote 10.

[16] 6 *N. S. Oxford Economic Papers* 231 (1954). Munby adds: "The politicians' argument that a group which has benefitted for many years at the expense of the rest of the community has a prescriptive right to continue to benefit would prevent the rational use of the price system at all." See also I. M. D. Little, *The Price of Fuel* (Oxford, 1953), p. 49.

[17] A. M. Milne, *The Economics of Inland Transport* (London, 1955), pp. 158–159, 176–177. Along with other economists, Milne points out that uniformity of charges for first-class mail throughout an entire country, and regardless of distances, does not constitute a serious violation of the cost principle, since the major expenses here are for collection and delivery. Convenience is always a respectable ground for a disregard of minor cost differentials in rate making. On occasion, it may even be a valid ground for the disregard of major cost differences.

[18] I. L. Sharfman, *The Interstate Commerce Commission*, Vol. III B (New York, 1936), pp. 538–693. Among other examples of "formal uniformity" in rate making, Sharfman cites rates for shipments to the New York Port area denying to New Jersey any benefit of freedom from lightering costs; and a number of group rate cases including the milkshed cases.

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tomer's intake of service as measured by energy-consumption, passenger trips, passenger miles, etc. Variations in charges by reference to time of day, to "demand" charges, or to charges for "readiness to serve" are often resented as unfair even if they are entirely defensible—as is by no means always the case—on grounds of strict cost responsibility. A British rate expert, D. J. Bolton, has this point in mind when he writes that "many people's feelings of equity will be outraged by a method which, under any circumstances, makes no charge for plant used, even in a purely off-peak period; or which makes a very large change in allocation for a very small change in load." [19] And in an earlier book on electric rates, G. P. Watkins had the same point in mind when he suggested that the so-called "Wright" form of rate, which embodies a demand-cost factor in the energy charges, "is probably more acceptable to the public . . . because it appears to be merely a modified kilowatt-hour charge." [20]

Enough has been said in this brief review of "fairness" aspects of rate regulation to suggest why their influence has been found so frustrating by economists and by many rate experts. In the first place, there are no uniformly accepted, measurable standards of fairness. "Equity," writes Professor Lewis, referring particularly to demand-cost allocations, "will support anything." [21] And Commissioner Connole of the Federal Power Commission takes a similar position in expressing a preference for the relatively objective, capital-attraction test of adequate rates as against a test based on some subjective consideration of fairness. "I emphasize 'objective standard,' " he writes, "because any attempt subjectively to demonstrate concepts so abstract as justness and reasonableness suffers all too often from the legendary abuses of the old English equity courts, summarized in the familiar bromide that equity justice varies with the length of the chancellor's foot." [22]

But in the second place, some of the more widely held considerations of equity clash seriously, at times, with those criteria of

[19] Bolton, *Electrical Engineering Economics*, Vol. 2: *Costs and Tariffs in Electricity Supply*, 2d ed. (London, 1951), p. 140. Similar popular notions of equity have influenced the Federal Power Commission in its choice of arbitrary methods of capacity-cost apportionment in natural-gas rate cases. See p. 354, n. 16, *infra*.

[20] G. P. Watkins, *Electrical Rates* (New York, 1921), p. 53.

[21] W. Arthur Lewis, *Overhead Costs* (London, 1949), p. 47.

[22] "Current Thoughts on Natural Gas Regulation," a talk before the New York Society of Security Analysts, Dec. 26, 1956. Mimeographed, p. 6.

functional efficiency which have been the primary concern of the economists and which ought to be one of the major concerns of regulation. Even the good-faith considerations clash at times, despite the impelling reasons for giving them due recognition. But more serious are those deterrents not only to rational practice but even to rational thinking set up by what I have called the notional-equality standards of equity.

What, if any, contributions can public utility rate theory make toward the reduction in these conflicts among rival standards of fairness and between fairness standards and efficiency standards? At least at the present time, the major opportunity for contribution lies in a disclosure of the presence of these conflicts throughout the field of public utility regulation, in a careful analysis of their nature, and in an effort to bring them sharply to the attention of the interested public in general and of persons concerned with rate making or rate regulation in particular. I say "at least at the present time" because, even today, there persists a fairly general unawareness of the extent and significance of these conflicts, and a widely held tendency to assume an identity between the question whether rates are reasonable and the question whether they are fair.

Whether or not the rate theorist should go further and take part, in his professional capacity, in controversies about rival standards of fairness is another question. The answer usually given by economists is in the negative, on the ground that the question, being one of ethics, goes beyond their professional competence. But while this answer is a forcible one and justifies a warning by an economist that he is out of his special field in expressing views on equity, it does not carry the complete conviction suggested by its implied distinction between means and ends. For even standards of fairness are properly judged, at least in part, by their utilitarian values,[23] and this statement applies alike to good-faith standards and to

[23] Compare John Maurice Clark's observation that, under the modern workmen's compensation laws, principles of incentives have modified older conceptions of fairness as to employers' liability for accidents. *The Economics of Overhead Costs* (Chicago, 1923), pp. 33–34. Despite economists' frequent denial that considerations of fairness fall within their professional concern, a study of their expressed or implied attitudes on concrete issues of fairness makes it clear that these attitudes are decidedly influenced by their profession. What distinguishes non-Marxian economists, at least (I am not competent to comment on the Marxians), is not a readiness to take positions on economic policy in ruthless disregard of considerations of equity, but rather a tendency to tailor their own conceptions of equity so as to bring them more nearly into harmony with their own conceptions of economic efficiency.

standards of fair income-distribution. The really serious obstacle to rational solutions of questions of economic policy involving issues of fairness lies, not in the philosophical insolubility of any dispute about ultimate ends, but rather in human inability to predict remote consequences. But in making attempts at a prediction, an economist is entitled to use whatever training and experience he may have in doing his fumbling best.

In any case, one conclusion as to the proper role of fairness standards in the determination of reasonable rates seems to me to be clearly justified: namely, that this role, though essential, should be a subordinate one, in that considerations of fairness or equity, when calling for separate recognition, must be regarded as restraints against the unqualified acceptance of general principles of rate making based on considerations of maximum economic or social efficiency.[24]

[24] I doubt whether this conclusion would be justified if carried over from the field of price policy to the field of tax policy, in which income-redistributive objectives properly receive much greater emphasis. See C. Lowell Harriss, "Sources of Injustice in Death Taxation," 7 *National Tax Journal* 289–308 (1954).

IX

RATE-LEVEL STANDARDS AND RATE-STRUCTURE STANDARDS

Problems as complex as those raised by modern price theory and rate regulation are best analyzed by the technique of cross-classification. Following this technique, the last chapter has cut across the previously discussed list of alternative criteria of reasonable rates in order to draw a distinction, familiar in the economic literature but not so often recognized in practice, between fairness conceptions of reasonable rates and economic-efficiency or social-efficiency conceptions. It is now time to turn to another distinction: that between the determination of a company's general *level* of rates, and the determination of *specific* rates or rate relationships. In the words of the late Chief Justice Stone, speaking for the Supreme Court in *Federal Power Commission v. Natural Gas Pipeline Company*,[1]

> The establishment of a rate for a regulated industry often involves two steps of different character, one of which may appropriately precede the other. The first is the adjustment of a general revenue level to the demands of a fair return. The second is the adjustment of a rate schedule conforming to that level, so as to eliminate discriminations and unfairness from its details.

Following the order of precedence thus suggested by Justice Stone, the chapters of Part Two will be concerned with rate-level determination under the standard of a "fair return," while the chapters of Part Three will discuss the far more complex problems of rate-structure determination. But the distinction between rate-level and rate-structure problems is one of convenience rather than one of analytical logic. The really basic distinction is that between

[1] 315 U.S. 575, 584 (1941).

an adequate-revenue or fair-return standard of reasonable rates and all other standards including those implied by rules against undue discrimination. Because the tests of a fair or capital-attracting rate of return are tests of adequate revenues from a public utility business in gross, or at least from a major division of that business, they are naturally associated with general rate "levels" rather than with specific rate differentials. The levels must suffice to make rates as a whole cover costs as a whole, including (or plus) a proper allowance for interest and profits. But the ability of a company to secure adequate over-all revenues depends on the structure of the rates as well as on their average height, as every management knows when it undertakes to improve its earnings by means of promotional rate reductions. Hence, even a so-called "revenue case," which involves a proposal for a fairly general increase or decrease in rate schedules designed to balance total revenues against financial requirements, raises at least incidental questions about proper rate relationships.

THE ASSUMED PRIORITY OF THE FAIR-RETURN STANDARD

Writers on the principles of public utility rates naturally dislike to deal with fuzzy rules or measures of rate determination. They are therefore under pressure to state these rules with a precision and definiteness that belie their nature in application or even in carefully expressed legal doctrine. This tendency is sometimes revealed in comments on the "fair-return" standard of reasonable utility rates. While all informed writers recognize that public utility companies are not *guaranteed* the enjoyment of a fair return, some of them have implied that neither statute laws nor public service commissions may impose rules of rate making which would deny a company whatever opportunity to enjoy such a return may be open to it in view of the potential demand for its services. Also, though less frequently, some writers have implied that the rates charged by any public utility must be deemed excessive, and hence subject to prompt reduction by voluntary action or by commission fiat, if the revenues therefrom are yielding more than a fair return and give promise of so doing in the future.[2]

[2] The fair-return standard probably has a firmer legal standing as a test of minimum rates than as a limitation on rate levels. Indeed, the standard was first developed in this country, in the form of the doctrine of a "reasonable return on fair value," as setting constitutionally imposed limits beyond which a legislature or legislative agency might not go in restricting a public utility's opportunity to charge compensatory rates. In some of its earlier opinions, the Supreme Court stated that, under ordinary conditions, "reasonable" rates might well be higher than those sufficient to yield a "fair rate of return." But the Court's views as to what return was fair were so liberal that public utility representatives at times publicly expressed their satisfaction with earnings insufficient to yield the constitutional minimum! See New York State, *Report of Commission on the Revision of the Public Service Commission Laws* (Albany, 1930), Minority Report of Messrs. Walsh, Bonbright, and Adie, N.Y. Legislative Doc. No. 75 (1930), pp. 52–55.

Modern public utility statutes, in setting forth general standards of rate control for observance by commissions, often include fair-return tests as factors to be "considered." Thus the New York State law governing gas and electric rates permits the Commission to "consider all facts which in its judgment have any bearing upon a proper determination of the question although not set forth in the complaint and not within the allegations contained therein, with due regard among other things to a reasonable average return upon capital actually expended and to the necessity of making reservations of income for surplus and contingencies." L. 1910, Chap. 480, Sec. 72, as amended L. 1934, Chap. 212.

This twofold assumption is not only convenient but almost essential for any simple exposition of rate theory developed under the constraint of a "budgetary" or fair-return standard. It fixes the status of this standard by giving it not just major importance but overriding priority. Strictly construed, it would predetermine not only the level but the pattern of a company's rates in the event that only one set of rates would yield the required net return, or in the event that one set would clearly come closer to this objective than any other set. Only if the company has redundant potential earning power, so that it could earn its allowed fair rate of return by any one of a variety of rate structures, would there then be room for the imposition of rules of rate making that contravene the objective of maximum profits or minimum deficits.

Not only is the above-noted assumption convenient for purposes of analysis. In addition, its acceptance reflects, as a first approximation, the actual practice of American rate regulation as applied to those public utilities enjoying a high degree of monopoly power—notably, the electric, gas, and telephone utilities. But it is never strictly valid either in legal doctrine or in practical application. And one need only look to the railroads for a situation in which it is far removed from the facts of life. To be sure, the railroads are now faced with such severe competition from road, water, and air carriers that most of them would probably fail to earn a conventional "fair rate of return" even if freed from all rate regulation. But one can hardly doubt that their earning power is further restricted by the application of commission-enforced rules of reasonable or nondiscriminatory rates—rules that do not yield priority to any assumed fair-return standard.

The full extent to which fair-return measures of reasonable rates may be made to give way, in practice, to other criteria of reasonableness is doubtless obscured by the very flexibility of the measures themselves. Persons who have made a close study of the rate cases will almost surely recall cases in which commissions seem to have reasoned backward, from their convictions as to what rates are reasonable to their findings as to what rate of return (or what rate base) is fair. But we may pass this point in taking note of *open* conflicts between the principle of a fair return and the principles governing specific rates or rate relationships—conflicts in which the latter principles sometimes emerge victorious.

Let us first recall that the primary verbal rule of public utility law in America, so far as concerns the rates of charge for service, is the twofold rule that rates must be both "reasonable" in themselves and not "unjustly discriminatory" in relation to other rates charged by the same enterprise. Only indirectly may this rule invoke a test of reasonable rate *levels*. In its immediate application, it is a rule for the determination of specific rates or rate schedules; and at least as a matter of formal doctrine, it is not subject to the proviso that a company may charge "unreasonable rates," or rates that involve "undue discrimination," in the event that these otherwise forbidden practices are an essential means of yielding adequate corporate revenues.[3]

The most obvious possible conflict with the fair-return objective is that raised by various restrictions against rate discrimination, a subject reserved for discussion in Chapter XIX. While the law does not forbid all forms of discrimination, despite careless statements to the contrary in much of the literature, and while commissions may tolerate, as necessary for the maintenance of sound corporate credit, forms or degrees of discriminatory rate making that they might otherwise forbid, there is a limit to this tolerance in that the discrimination must not be of a type which seriously injures customers in their competition with other customers. Discrimination of this character will be deemed "undue" or "unjust" and presumably would not be excused even as a necessary means of forestalling corporate insolvency. The same statement applies a fortiori to certain types of discrimination expressly outlawed without qualification by statute, notably so-called "personal discrimination."

[3] The Supreme Court may have had this point in mind in the early history of rate regulation when it qualified its famous fair-value rule of rate making by the statement that a public utility may not exact from its customers charges higher than the services "are reasonably worth." Smyth v. Ames, 169 U.S. 466 at 546–547 (1898). See pp. 85–86, *supra*.

As to the possible conflict between the fair-return standard and the requirement that each rate must be "reasonable per se," without reference to any complaint of undue discrimination, the subject presents more difficulties from the standpoint of rate theory.[4] But the railroad rate cases supply examples of such a conflict, in the form of decisions by the Interstate Commerce Commission restricting the opportunity of railroads to make up deficiencies in the revenues received from highly competitive business by attempts to secure "unduly" high returns from noncompetitive or less competitive business.[5] In other words, the right of the carriers to enjoy a fair return on their entire business is subject to their ability to secure these returns by means of rate schedules that are not "unreasonable" in the extent to which they share in the coverage of overhead costs, and not unjustly discriminatory in their relation to other rates available to competing shippers.

SUBORDINATE POSITION OF THE FAIR-RETURN STANDARD IN THE REGULATION OF RAILROAD RATES

The warning, expressed in the previous section, that the fair-return standard is not an overriding rule of rate making, applies in principle to public utility industries in general, including the so-called municipal utilities as well as the railroads. All of these utilities are under a mandate to charge specific rates that are both

[4] The major theoretical difficulty is that of reconciling commission decisions restricting the opportunity of railroads or other public utilities to charge "disproportionately" high rates for noncompetitive service, with the acceptance by the same commissions of value-of-service principles of rate classification—principles which recognize that the types of service for which there is a more inelastic demand may properly be called upon to pay larger shares of the overhead costs. It would seem that a rate may be found "unreasonable" on the ground that it carries the value-of-service principle to excess. But I doubt the existence of any definite rule by which to draw the line of tolerance.

[5] In support of the position that rate-of-return standards must sometimes bow to specific-rate standards, not alone on the count of unjust discrimination but also on the requirement of "reasonableness per se," see the "Lignite Case," Northern Pacific R. Co. v. North Dakota, 236 U.S. 585 (1915).

"reasonable" and not "unjustly discriminatory"; and none of them can adduce either a constitutional or a statute-supported claim to a fair over-all return as exempting them from this twofold legal obligation.

But in the actual practice of rate regulation, the fair-return standard comes much closer to dominance with respect to those utilities that enjoy a high degree of monopoly status than it does with respect to the transportation companies, including the railroads. Indeed, in the regulation of the railroads during the past quarter of a century, the fair-return standard has been so submerged under a combination of competitive conditions and statutory or commission-enforced rules governing the rate structure, that it can hardly any longer be deemed an operating principle of rate making. Only in occasional years have the American railroads, taken as a whole, succeeded in earning on their invested capital or on their property "values" rates of income that would approximate a "fair rate of return" under traditional tests of fairness.[6]

This striking difference between the railroad situation and the local-utility situation is not due to any fundamental differences in the legal rules of rate making. It is due rather to the difference in the impact of these rules. With the local utilities, the fair-return standard has been actually applied, not because it here enjoys a legal priority over all other rules but rather because its application has not often imposed an intolerable constraint on the pattern of the individual rates. But with the railroads, the conflict between the fair-return standard of aggregate rates and the accepted criteria of proper specific rates and rate relationships has been so severe that the former standard has had to give way, not just occasionally but chronically.

Two circumstances in combination account for this difference between the dominance of the fair-return standard in the regulation of the electric, gas, and telephone utilities, and the submerged status of

[6] During the ten-year period 1949–1958, the reported ratios of net railway operating income to depreciated property investment for the line-haul, Class I railroads of the United States averaged 3.68 per cent per annum, with a minimum of 2.76 per cent in 1958 and a maximum of 4.28 per cent in 1950. Association of American Railroads, Bureau of Railway Economics, *A Review of Railway Operations in 1958* (Washington, D.C., 1959). What the rate of return might have been if applied to a "rate base" measured by current replacement costs but subject to full deductions for the obsolescence of railway transport as a whole is an unanswerable question.

the same standard in railroad regulation: first, the far more widespread and severe competition faced by the railroads; and secondly, the tendency of freight shippers to attach more importance to the relationship between their rates and rates paid by competing shippers than they attach to their absolute rates.[7] The first factor has put the railroads under special pressures to quote rates little higher than out-of-pocket costs for their highly competitive traffic and hence to make up for the resulting revenue deficiencies by disproportionately high rates for their less competitive traffic. But the second factor has put the Interstate Commerce Commission under special pressure to resist this tendency by the application of rules against undue discrimination. So serious has this situation become that a thorough overhaul of railroad rate regulation under the Interstate Commerce Act has been demanded, not just by the railroads but by many nonpartisan experts. A move in this direction was made by the Cabinet Committee Report of 1955, the "Weeks Report," which proposed to give the railroads much greater freedom in setting competitive rates. Under its recommendations, the Interstate Commerce Commission would be deprived of its present powers to set the exact railroad tariffs and would be limited to the setting of upper and lower limits of "reasonable" rates, although remaining under the difficult duty of enforcing rules against "undue" discrimination.

For the reasons just suggested, any author of a modern treatise on transportation rates in general and railroad rates in particular is under impelling pressure to put the fair-return standard of reasonable rates in a subordinate, or at least in an uncomfortably unsettled, position.[8] No longer can he usefully assume, even as a rough approximation, that the determination of individual rates or

[7] A possible third, contributory reason is suggested by the recent contentions of rate experts, led by Mr. John Alden Bliss, that public utility rate structures are far better designed than are railroad rate structures to meet competition without sacrificing adequate returns. The superiority of the utility rates is believed to lie in their resort to multi-part pricing based on multi-part cost functions. See the articles cited in Chap. XVI, footnote 22.

[8] The later editions of Professor D. Philip Locklin's standard treatise on the *Economics of Transportation*, departing from the chapter sequence of earlier editions, put the chapter on fair return in the middle of the section on tariffs and without implying a dominant status in rate regulation. In their *Economics of Transportation*, rev. ed. (New York, 1959), Professors M. L. Fair and E. W. Williams relegate their chapter "Railroad Rate Level and Financial Return" to the end of their study of railroad rates.

rate differentials, however important, is nevertheless a strictly secondary problem, the solution of which is subject to a prior principle that rates as a whole shall be designed, as far as possible, to yield a fair return. Instead, one of his major problems—a frustrating one at that—is to suggest possible resolutions of the conflict between fair-return standards and other rate-making criteria, or else to propose alternative forms of rate regulation that completely reject the fair-return philosophy. The alternative criteria include not only nonrevenue considerations but also revenue standards of a short-run or emergency character distinguished from those of a fair return in its usual sense. For example, in a recent general rate-level case brought by the railroads, *Ex Parte 175* (1951),[9] the Interstate Commerce Commission's grave concern for the carriers' financial needs led it to grant substantially the full requested proportionate rate increases despite forcible objections from certain classes of shippers, including the coal shippers, that were being forced to make good deficiencies in other parts of the railroad business, notably in the passenger business. But the financial needs emphasized by the Commission were specific, short-run needs for equipment and plant, not revenue requirements as measured by the traditional standards of fairness or even of long-run financial health and vigor.

But only incidentally is the present book concerned with transportation rates, and then mainly for purposes of comparison. Instead, its primary interest is in rate control as applied to the more nearly monopolized public utility industries. Here, the convenience of the assumption of priority for the fair-return standard outweighs its inaccuracy. Hence the chapters on fair return will come first, in Part Two, and all but one of the later chapters on rate structure (Part Three) will assume that this structure must

[9] 297 I.C.C. 17 (1951). Compare the following statement by Mr. J. C. Kauffman, Vice President and General Counsel of the Chesapeake and Ohio Railway Company: "Within my span of about thirty-five years of railroad experience, I have never seen a charge that the railroad industry was making more than a fair return. Our problem is to find enough income to live on, to sustain the railroads in their day-to-day operation and to provide funds for capital expenditures. We don't have to worry about their rate of return in the language of the public utilities, when we are earning about three and a half per cent on any fair evaluation of our property." Appearance for the Association of American Railroads before the Interstate Commerce Commission in hearings on a proposal for the creation of tax-equalization reserves for defense amortizations, Stenographer's Minutes, June 26, 1956.

be designed under the constraint of a fair-return rule. The exception is Chapter XX, which will discuss proposals by an important group of economists that public utility rates be based on marginal costs, regardless of the resulting effect on total revenues.

PART TWO

Fair-Return Standards of a Reasonable Rate Level

X

CRITERIA OF A FAIR RETURN

As already indicated, a fair-return or fair-profit standard of reasonable rate levels is generally accepted throughout the United States as a controlling basis of rate regulation with respect to those privately owned public utilities that have excessive potential earning power by virtue of their protected, monopoly status. But even when a fair-return standard is accepted in principle, and even if it were enforced in practice with much greater rigor than has been customary,[1] it would still be far from supplying a definite basis of rate control. For a mandate that the sought-for return shall be fair carries with it no instructions as to the criteria of fairness. The history of American rate regulation is in large measure a history of attempts by courts, legislatures, commissions, and economists to supply these criteria. But even today the subject remains highly controversial.[2]

[1] Commissions have seldom attempted a rigorous, mechanical application of the fair-return standard through regular, periodic reviews of rate levels. Instead, they have tended to let the existing rate levels stand, subject to minor revisions in the rate pattern, until there appears to be an impelling reason for a new general rate case. The impulsion may come from the company in the form of a petition for authority to increase the rates, or else from consumer spokesmen in the form of a complaint that the existing rates are too high. But the ablest commissions will themselves take the initiative on behalf of consumers if their expert staffs are convinced that a review is called for. Even with these commissions, however, one should not assume that a rate hearing will at once be instituted if actual corporate earnings materially exceed the "fair rate of return" accepted as the basis of the last rate order. Quite aside from the recognized undesirability of too frequent rate revisions, commissions recognize the "regulatory lag" as a practical means of reducing the tendency of a fixed-profit standard to discourage efficient management.

[2] A complete treatise on public utility rate regulation would not limit its discussion of revenue requirements to the two components of these requirements considered in this book—the fair return and the related problem of the annual allowance for depreciation. In addition, a review and critique of commission allowances for all operating expenses would be called for. See, e.g., Eli W. Clemens, *Economics*

Until a few years ago, any discussion of the subject from the standpoint of practical application necessarily included elaborate commentaries on the partly indeterminate, partly conflicting legal precedents established by the Supreme Court in the form of constitutional restrictions against the power of government to fix prices that would impair the profit-making opportunities of individual or corporate owners of private property. While these owners were held subject to rate regulation if engaged in a business "affected with the public interest," they were also held entitled to protection against regulation so stringent as to violate the injunctions of the Fifth and Fourteenth Amendments against the taking of property "without just compensation" or "without due process of law." In 1898, in its famous dictum in *Smyth v. Ames*,[3] the Supreme Court established the fair-value rule as setting the normal limit below which rates, if imposed by legislative or commission fiat, would be held "confiscatory." But since "fair value," used in this context, is an ambiguous and confusing term, and since the norm of a "reasonable" or "fair" rate of return on this value is also indefinite, long articles and even large books were written by lawyers, economists, and valuation experts on problems of "interpretation."[4]

Fortunately for the cause of continued private ownership of American public utilities, this submergence of important practical issues of effective regulation by esoteric legal issues no longer prevails throughout the country in view of the notable change in the philosophy of the Supreme Court as reflected not only by its decision, but by all of the five separate opinions of the justices, in the *Hope Natural Gas* case.[5] While judicial precedents on the measurement of a valid rate base and of an adequate rate of return are still

and Public Utilities (New York, 1950), Chaps. 6 and 22; Emery Troxel, *Economics of Public Utilities* (New York, 1947), Chap. 11.

[3] 169 U.S. 466 (1898). See pp. 163–166, *infra*.

[4] A summary of the early rulings and opinions on "fair value" is contained in Chaps. 30 and 31 of my *Valuation of Property* (New York, 1937). John Bauer and Nathaniel Gold published a monograph on the subject as a part of a series of studies of legal valuation prepared under my editorship. *Public Utility Valuation for Purposes of Rate Control* (New York, 1934). In the more elaborate early treatises, entire chapters were devoted to single components or "elements" of value, such as "going value," land valuation, and the hypothetical replacement costs of pavements over mains. See Robert H. Whitten, *Valuation of Public Service Corporations*, rev. ed. by Delos F. Wilcox, 2 vol. (New York, 1928).

[5] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

important, and while they are controlling in any one jurisdiction when set forth in definite terms, they no longer constitute an elaborate "law of the land" as did the earlier rulings made under the influence of the fair-value doctrine. Moreover, since they are for the most part interpretive of statute law rather than of constitutional mandate, they are subject to change by statutory amendment. Hence, they will receive only incidental attention in these chapters, which discuss the criteria of an adequate return from the standpoint of the economic objectives of rate control and by reference to common-sense considerations of fairness between investors and consumers.

THE RELEVANT MEANING OF A "RETURN"

Under the usual forms of American public utility regulation, a "fair return" represents the entire excess in operating revenues, over and above current operating deductions, for which a commission will make provision in a rate case as a component of the company's annual revenue requirements. The operating deductions include allowances for depreciation and for nearly all taxes, not even excepting corporate income taxes. But the return in excess of these annual deductions does not coincide with corporate "net profit" or "net income" in an accounting sense, since it covers allowances for interest charges as well as for earnings on the stock equity. The published corporate earnings statements do not set forth the amount of return that a commission may have found "fair," nor even the precise return actually realized as measured by rate-making technique. But the reported "net operating income" is often an approximation of this latter figure.

In orthodox practice—and most regulation remains orthodox in this respect regardless of its choice between "original-cost" and "fair-value" principles of rate making—the allowed-for return is arrived at as a multiple of two factors: the rate base, and the "reasonable" or "fair" rate of return thereon.[6] The rate base, or "valu-

[6] In this country the most significant recent departure from a rate-base measurement of a fair return has been that of the "operating-ratio standard," applied to the passenger-bus and motor-truck industries by the Interstate Commerce Commission and by some state commissions. See Alan Wright, "Operating Ratio—A Regulatory Tool," 51 *Public Utilities Fortnightly* 24–29 (1953); Laurence S. Knappen, "Transit Operating Ratio—Another View," 51 *Public Utilities Fortnightly* 485–497 (1953); Charles W. Knapp, "Economics of Transit Operating Ratio," 56

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ation" as it was called in former years, represents the total quantum of invested capital or of property "values" on which the company is entitled to a reasonable rate of compensation. The "fair rate of return" reflects whatever annual, percentage rate is found appropriate in the light both of historical conditions and of conditions prevailing or anticipated at the time of a rate case. Thus, the acceptance by a commission of a sum of $100,000,000 as the rate base, combined with a finding that 6 per cent constitutes a fair rate of return, will result in an allowance of $6,000,000 per annum as the fair-return component of the company's revenue requirements. But since general rate levels are seldom revised annually and are likely to stay put for the indefinite future, the tariffs approved by the commission may be designed to yield a reasonable rate of return on the average, over the next few years. Under this objective, account may be taken of future growth of capital investment and of net operating income as the company's plant and business expand.[7]

Public Utilities Fortnightly 467–479 (1953); National Association of Railroad and Utilities Commissioners, Report of the Special Committee to Study Principles of Rate Regulation in the Motor Bus Industry, *Proceedings*, 64th Annual Convention (1952), pp. 461–470; and commission and court opinions noted in these citations. The affected industries have favored the newer technique since, as usually administered, it has conceded much higher profit-making opportunities than would the orthodox technique if applied under traditional standards of a fair percentage rate of return. But, to the best of my knowledge, the supporters have not yet succeeded in finding a convincing rationale of an operating-ratio standard, nor have they yet effectively answered adverse criticisms such as those advanced by Mr. Knappen in the article noted above. The situation now calls for a thorough and objective reexamination, made in the light of actual experience in attempted application.

[7] Commission orders approving a rate-level increase or requiring a decrease are usually based on findings that, in the light of recent realized earnings, the existing rates would probably yield a deficient, or an excessive, rate of return in the near future. As a guide to such a finding, a commission may first determine the return realized during some twelve-month period taken as a "test year." In estimating the rate of return that may be earned during the next year, or during some other future period, the commission will accept convincing evidence of changes in operating expenses and in other operating deductions. Indeed, even in its finding of the rate of return already earned during the test year, a commission may substitute pro forma operating revenues and operating deductions designed to reflect current financial conditions. Payroll expenses, e.g., may be restated in terms of changed rates of wages. As to the rate base applicable to the test year, the usual procedure has been to accept some midyear rate base or some other average rate base in taking account of growth of plant investment during the very year under review. But in recent rate cases, some commissions that accept an actual-cost measure of the rate base have conceded a year-end rate base, presumably as a crude means of allowing for the so-called attrition factor during a period of price inflation. Discussion of these and other procedural details of rate control is beyond the scope of the present book.

Obviously, any assumption of an approximate offset between these two variables is likely to be belied by actual experience. Partly in view of this likelihood, partly because changes in financial conditions may justify changes in the allowed rates of return, companies and consumer groups are given the opportunity to institute a new rate case on a showing of plausible grounds therefor.

FIVE MAJOR CRITERIA OF A FAIR RETURN

In line with the usual procedure of American rate regulation, the four following chapters will consider the measurement of the rate base, leaving for a later chapter a discussion of the tests of a reasonable percentage rate of return on whatever rate base is accepted in a given jurisdiction. But by way of introduction, the present chapter will discuss briefly those major criteria of a fair or reasonable return by reference to which one may judge the merits of alternative measures alike of the rate base and of the rate of return thereon. The main purpose of this introduction is to guard against a tendency, to which some of the early Supreme Court opinions unfortunately lent support, to treat rate-base measurement and rate-of-return measurement as if they were governed by different standards of fairness instead of being merely two steps by which to determine corporate revenue requirements.

Let it be noted that the criteria under review are relevant, not just to the determination of the fair return in a given rate case but to the choice of an entire system of rate regulation applied with reasonable consistency over an extended period of years. What makes an allowed return fair in any specific rate case must be its fair conformity with the general principles applicable also in other years and under different conditions. Apart from such conformity, the fairness of the allowance at any one time is simply indeterminate. In an extreme case, for example, the allowance of a zero return or even of an operating deficit during a period of business depression may be quite "fair" and quite consistent with the need for capital attraction if imposed under a scheme of regulation that concedes to investors adequate opportunities to enjoy what would otherwise be excessive profits in times of prosperity. On the other hand, an allowed return of 25 per cent on the cost or "value" of the corporate properties might be penurious if rate-making policy should threaten to bring all profits to an end after the next several years.

1. THE CAPITAL-ATTRACTION CRITERION

Recalling, then, that we are concerned with the *principles* by which to measure a fair return rather than with details of application to any one case, what criteria of fairness or effectiveness should govern the choice of these principles? Among these criteria, high place, perhaps first place, must be given to that of capital-attracting efficiency. Judged by this test alone, choice should rest with whatever principles of rate control are best designed to permit well-managed, soundly financed public utility companies to attract needed capital.[8]

In view of the obvious plausibility of the capital-attraction standard of a fair return, one may raise the question why its recognition has not gone farther than it has to date in resolving the more serious controversies about principles of measurement. A partial answer is that, under favorable conditions, any of various systems of rate control can be so administered as to permit adequate capital financing.[9] Material scope for choice lies in the possibility of making alternative schemes attractive to investors by the introduction into each scheme of special attractions designed to offset special restrictions. Thus, any adverse effects of a system of regulation which denies to public utility stockholders direct protection against future price inflation may be offset by the concession of nominal rates of return more liberal than would otherwise be necessary. And thus, the deterrent effect of a rule of rate making which denies to a company the opportunity to amortize, through charges against consumers, the costs of property rendered useless by extraordinary obsolescence, may be counterbalanced by the allowance of returns on useful properties so liberal that investors are ready to take their chances of suffering for an uncompensated erosion of surplus, if and when the erosion takes place.

[8] "Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so-called 'fair-value' rate base." Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 605 (1944). Elsewhere I have discussed the significance and limitations of this famous pronouncement: "Utility Rate Control Reconsidered in the Light of the Hope Natural Gas Case," 38 *American Economic Review, Proceedings* 465–482 (May, 1948).

[9] The extent of the room for choice among alternative principles of rate control, any one of which might be expected to permit well-managed utility companies to attract needed capital, depends partly on the readiness of regulation, assisted by general corporation laws, to enforce compulsory financial reorganization as an effective means by which to bring the contractual interest and preferred-dividend requirements of public utility companies into conformity with the currently applied rules for the measurement of a fair return. For example, under a strictly enforced, fair-value rule of rate making, permitted dollar earnings might well fall to such low levels, during a period of price deflation, that even well-managed companies would suffer a serious impairment in credit and hence in their ability to serve the public. This impairment might be cured by a sufficiently timely and drastic reorganization involving the enforced readjustment of the contract rights of the senior security holders. But no one familiar with the prevailing law and practices of corporation reorganization could look with complacency on rules of rate making likely to give rise to the need for this kind of cure.

2. THE MANAGEMENT-EFFICIENCY CRITERION

In its analysis of the role of public utility rates, Chapter III distinguished between the function of rates in enabling a public utility to secure the capital required for the supply of the service, and the function of the same rates in stimulating managerial efficiency. Both functions may be at issue in the determination of a fair return. For the amount of the allowed return may be designed, not just to enable a company to attract capital but also to reward efficiency and discourage inefficiency of management.

More will be said about the management-efficiency criterion in Chapter XV. Here we merely note that an incentive standard of a fair return may come into conflict with other standards, especially with that of capital attraction. Such a conflict will become acute with respect to companies threatened with insolvency because of substandard earning power or of top-heavy capital structure for which the existing management, or some earlier management, has been at least partly to blame. In these situations, should commissions be especially lenient in their application of principles of rate control including allowances of a "fair return"? Or should they be rigorous in the enforcement of the general principles, possibly concluding that a "fair" rate of return for a poorly managed company is a very low return or even one expressed in red letters? Questions of this nature present serious dilemmas of rate-making policy.

3. THE CRITERION OF RATE-LEVEL STABILITY

If public utilities were required to raise and lower their rates year by year, with the object of maintaining a fixed annual rate of return, the resulting necessary changes in rate schedules would

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prove inconvenient alike to the consumers and to the corporate managements.[10] Even more serious would be the countercyclical direction of the change in rate levels required by an attempt to offset a depression-created decline in the demand for the service by an increase in the unit rates of charge. From an economic point of view, the most reassuring thing to be said about such an attempt is that it would be likely to fail!

The points just suggested raise one of the most difficult and most incompletely solved problems of fair-return determination. Most writers would probably agree that, during periods of prosperity, rates should be designed to yield profits sufficiently liberal to avoid the need for a countercyclical rate increase during a depression. But whether or not an attempt to secure cyclical flexibility in the right direction is desirable and feasible remains a highly controversial question. More will be said on this question in the chapter on rate of return; but the conclusions will be disappointingly uncertain.

4. THE CONSUMER-RATIONING CRITERION

Earlier chapters have called repeated attention to a possible conflict between a capital-attraction standard of reasonable rate levels and the "consumer-rationing" function of specific rates or rate differentials. Under the first standard, rates as a whole should cover costs as a whole, including the so-called costs of capital. Under the second standard, each rate should be designed to encourage all consumption for which consumers are ready to pay escapable, marginal costs, and so as to deter any consumption for which consumers are not prepared to pay these costs.

Economists, I think, would generally agree that no complete harmony between these two standards of rate making is possible. But those writers—and they are in the great majority—who do not accept proposals by Hotelling and other economists to abandon a full-cost or fair-return principle would tend to favor whatever feasible measures of a fair return may result in the least serious discord with standards of optimum specific rates and rate relationships.

[10] Compare the laws governing the rate-making practices of the nationalized British utilities, which call for the establishment of rates that will meet revenue requirements, including fixed charges, "taking one year with another." See W. A. Robson, ed., *Problems of Nationalized Industry* (New York, 1952), pp. 334–338.

In earlier years several economists, led by Professor Harry Gunnison Brown, defended the use of a reproduction-cost rate base as coming closest to a reconciliation between the principle that rate levels should be based on total cost of service and the principle that specific prices should be governed by specific costs or marginal costs, as they are supposed to be governed under competition. This line of defense is no longer as widely voiced as was formerly the case, for reasons stated in other chapters.[11] But it at least suggests one sought-for attribute of a fair-return program of rate control—the attribute of tolerable harmony with the demand-control or consumer-rationing objective of rate making.

5. THE CRITERION OF FAIRNESS TO INVESTORS

All four of the criteria of a fair return so far suggested might be classified as criteria designed primarily in the interest of the consuming public. But the very term "fair return" implies a standard of equity to investors not necessarily governed by considerations of consumer self-interests. Certainly this implication is borne out by the history of rate-making law. For the traditional rules of fair-return determination were originally developed by the courts as a means of protecting the private owners of public utility properties against "confiscatory" regulation. And even in those jurisdictions which today deviate from some of the older rules, public utility companies have an undeniable right to challenge the fairness of the newer practices.

But granting, as we must, that a "fair return" must be fair, we may still raise the question whether considerations of fairness to investors require the importation of *special* criteria, in addition to those criteria which would be justified solely in the long-run interests of the consumers themselves. A negative answer would, of course, greatly simplify the solution of problems arising in a rate case. And such an answer would at least be plausible, since it rests on the ground that most public utility companies, in order to render good service, must be able repeatedly to attract new capital

[11] See pp. 101, *supra*, and 224–237, *infra*. Compare the contentions of some British economists that the rates of the nationalized public utilities should be designed to cover, not the fixed charges imposed by the securities issued as compensation to the investors in the expropriated private companies, but rather computed interest on the appraised "values" of plant and equipment. References cited in Chap. XIV, footnote 16.

from investors who are free to commit their funds to any alternative investments including the purchase of stocks in unregulated corporate enterprise. Market acceptability may thus be thought to become, at one and the same time, the test of fairness and of corporate financial need.

Stated in terms of a very broad generalization, the point of view just suggested may be accepted. But, at least under the prevailing American types of rate regulation, the principle is subject to serious qualifications—so much so that disputes about equity intermingle in a most confused way with disputes about functional efficiency. The trouble arises because of the likelihood that, after a public utility corporation has already become established as a going concern, with possession of a large plant and with a fixed security structure, rates of earning that will permit it to attract new capital on whatever terms the current market may require do not necessarily correspond to rates of earnings that are fair to existing investors. Yet, in any given rate case, the only return *directly* at issue is, not the return necessary to attract new capital but rather the return necessary to compensate the existing investors for capital already attracted or for the use of properties already acquired with this capital.[12]

The situation would be quite different if the principles of American rate regulation were so unchanging and so determinate in their measurement of a fair return that all public utility investors could be deemed to have been put on constructive notice of the restrictive character of the regulation prior to their commitment of capital. But neither of these assumed conditions has prevailed down to date. In the first place, there have occurred important retroactive shifts in the "rules of the game"—shifts such as that from a "fair-value" rate base to an "actual-cost" rate base, or from retirement-expense accounting to accrued-depreciation accounting. And in the second place, the rules themselves, at any given time and in any single jurisdiction, are too indefinite to predetermine the reasonable expectancies of the purchasers of utility securities except within fairly wide limits. These purchasers are not in

[12] This is not to say that a capital-attracting rate of anticipated income on new investment has no bearing on a fair allowed rate of return on capital already invested. But the bearing must depend on the indirect argument that existing, captive investments are fairly compensated if permitted to receive whatever rates of return would currently induce free investments.

the happy position of the old lady who said that she always ordered hash in a public restaurant because she knew just what she was getting!

The conclusion that indeterminate rules of rate making are largely responsible for disputes about the fairness of commission actions is suggested by the relative freedom from similar disputes enjoyed by publicly owned utility enterprises financed without pledge of government credit by the issuance of revenue bonds. Here, the income claims of the investors are definitely established in the contracts, which also contain mandatory provisions for whatever increases in utility rates may be required to protect the debt service. Similar relative freedom from fairness questions has prevailed under private ownership with respect to companies that have issued fixed-dividend common stock, in the manner of the earlier British gas and electric companies.

But in this country, regulatory policy, following common-law traditions, has insisted on retaining material flexibility as to the measurement of a fair return. Investors in utility securities, notably in common stocks, must therefore take their chances as to the effect of future rate cases, or even of future amendments to regulatory law, on the earning power of the companies in which they invest. Today, for example, they may hold stock in a company which, under a statute law as interpreted by the courts, is entitled to charge rates designed to yield a "reasonable" rate of return, not on the cost of its properties but on their present "fair value." But no one can assure them that the fair-value rule will be in effect five years from now. And even if that assurance were forthcoming, not even an expert could tell them how this vague, ambiguous rule will be interpreted by a new commission or by a new set of appellate judges.[13]

In the present, unsettled stage in the development of public utility rate theory and practice, this American policy of flexibility

[13] The unfeasibility of any attempt to give to prospective purchasers of public utility securities definite and reliable information about the governing rules of rate regulation is apparently recognized by the (Federal) Securities and Exchange Commission. For the registration statements and prospectuses of public offerings of utility securities say little or nothing about the nature of these rules. Thus, a recent prospectus (Commonwealth Edison Company, April 15, 1958, $50,000,000 issue of First Mortgage 3¾ per cent Bonds), in referring to regulation, merely states the names of the commissions having jurisdiction over the company or its affiliates together with the *types* of regulation to which the company is subject (rates, issuance of securities, etc.).

and indeterminacy may be defended on the ground that a policy which makes no positive commitments is better than one which makes the wrong commitments. But as long as the indeterminacy exists, issues of *fairness*, both to investors and to consumers, cannot be ruled out of controversies about the meaning and measurement of a fair return. The best prospect of minimizing these frustrating issues lies in the gradual development of more definite rules, which may become more and more firmly established as their application stands the test of experience.

The points discussed in this introductory chapter on the criteria of a fair return repeat, with variations, the main theme, or "leitmotif," of this entire book on standards and measures of reasonable public utility rates. This theme runs to the effect that the standards of reasonable rates are multiple standards, and that all of them at times come into conflict with one another. It applies both to the criteria of reasonable rate levels and to the criteria of reasonable rate structure or rate differentials. In the determination of the rate levels, capital-attracting adequacy is properly considered a basic test of a fair return. But other criteria of reasonableness, notably the four others summarized in the preceding paragraphs, must also be taken into account, alike in the design of the rate base and in the determination of formulas or principles for the measurement of a fair allowed rate of return on whatever rate base may be accepted.

XI

THE RATE BASE: COST OR VALUE

The various objectives of rate-making policy reviewed in the preceding chapter are relevant to the entire determination of a fair return in terms of dollars per annum. But the amount of this return is usually calculated through the application of a percentage rate to a so-called rate base. We now turn to the measurement of this rate base—the most widely disputed legal issue in the history of American public utility regulation. But, for the most part, the discussion will be analytical rather than legal or historical, and the reader must turn elsewhere for a study of the case law and for a review of the actual American experience with regulation under the old "fair-value" doctrine of the Supreme Court—an experience so dismal that, in my opinion, it constituted a serious threat to the long-continued survival of regulated private ownership.[1]

The general principles of measurement are usually subject to only minor disputes with respect to plant newly constructed or equipment newly acquired in arms' length transactions. Here, actual, legitimate cost of plant and equipment, with "reasonable" allowances for interest during construction and for working capital, is the governing basis of calculation. But with the lapse of time between the dates of acquisition and the date of a rate case, the room for controversy widens. There now arise numerous plausible grounds for claims by opposing parties that the original-cost entries should be either disregarded or subject to revision: because the

[1] Most of the case law referred to in this chapter is reviewed in Chaps. 30–31 of my *Valuation of Property* (New York, 1937). See also the other references in footnote 4 of Chap. X. The adverse opinion expressed above about the actual experience of regulation under the fair-value doctrine is substantially the one that I expressed in 1930 in the Minority Report of the *Report of the Commission on the Revision of the Public Service Commission Laws*, a report signed by Commissioners Walsh, Bonbright, and Adie, N.Y. Legislative Doc. No. 75 (1930), pp. 334–410.

plant has been transferred to another company at a higher or lower "acquisition cost"; because the assets have ceased to be "used and useful" in the public service; because these assets, even though still useful, have undergone depreciation in efficiency or in life expectancy; because a part of their costs has already been recouped by the company through amortization or depreciation charges allowed as operating deductions; because current replacement costs would be higher or lower than historical costs; because increases or decreases have taken place in the "general price level" and hence in "the value of the dollar"—in short, because the original costs have lost their original economic significance.[2]

Within recent years, at least, the major division of practice and opinion on these issues of asset "revaluation" has been between the position that, as long as the assets remain "used and useful" for their intended purposes, they should stay in the rate base at their original costs, subject only to systematic annual deductions for physical and functional depreciation; and the position that the costs should be written up or down so as to take account of major changes in construction costs or in general price levels. The first position is that of the "original-cost" or "net-investment" principle of rate making —a principle strongly espoused by the Federal Power Commission and now accepted, with or without qualifications, in the majority of jurisdictions. The second position is most frequently referred to as the "fair-value" principle—a principle no longer held legally mandatory throughout this country but still accepted in a considerable minority of states.

But the prevailing tendency to identify *any* departure from a net-investment or actual-cost standard of rate making with a "fair value" standard, at least whenever the departure takes account of current construction costs or current price levels, is both inaccurate and confusing. For it seems to imply the existence of only two alternatives, the one calling for a rate base measured by a historical record of depreciated cost, the other calling for a rate base designed to reflect, not the costs of the assets in *any* sense but rather what they are "fairly" or "really" worth at the time of a rate case. This loose and indiscriminate use of the ambiguous term "fair value" as an antonym for original cost conceals the presence of other significant alternatives, such as the adherence to an original-cost figure restated in terms of dollars of equivalent current purchasing power. It also obscures the prevalent use of "fair value" to mean, not a definitive measure of the rate base but rather an eclectic or compromise standard, which somehow splits the difference between conflicting measures.

In the hope of minimizing this confusion, the present chapter will consider the basic distinction between cost and value factors in rate-base determination and will stress the point that value considerations are by no means absent even under the so-called original-cost or net-investment principles of rate control.

THE RATE BASE AS REPRESENTING CONTRIBUTED CAPITAL VERSUS THE RATE BASE AS REFLECTING THE VALUE OF THE ASSETS

By way of noting the interplay between cost and value considerations in rate-base determination, let us return to those occurrences, already mentioned, that may be claimed to have impaired the "economic significance" of the unadjusted, original-cost data. A review of these claims suggests two, quite different conceptions of the nature of the alleged impairment. According to the first con-

[2] There is an obvious similarity between these problems of rate-base determination and problems of fixed-asset valuation in financial accounting. The similarity is much closer under an actual-cost or net-investment principle of rate control than under a reproduction-cost or "fair-value" principle. Indeed, the shift from a fair-value to a net-investment principle is often characterized, aptly though not with complete accuracy, as a shift from the realm of the appraisal engineer to the realm of the accountant. Hence, appraisal engineers may not welcome the shift! But even under a net-investment standard of rate control, the similarity between rules of accounting "valuation" and rules of rate-making "valuation" does not reach the point of identity, although it is being gradually increased through a shift in the accounting rules themselves as prescribed by commissions for application to public utility and railroad companies. The shifts are designed, sometimes to tighten, sometimes to depart from, those "generally accepted principles of accounting" applied to unregulated enterprises, so that the regularly recorded book values of the public utility assets can be used with minimum revisions as components of a rate base.

In disputes between company representatives and commission staff experts as to the proper measure of the rate base, both sides have sometimes appealed to "generally accepted principles of accounting." Thus, companies seeking inclusion in the rate base of any price at which they may have acquired public utility plants from other companies, however much in excess of original construction costs, have produced expert accounting witnesses to support their contention that arms' length acquisition costs are the relevant costs for accounting recordation by the acquiring enterprise. (See p. 175, *infra*.) And thus, some commission staff experts, in seeking to deny or restrict rate-base allowances for interest on work under construction, have pointed to the scant recognition given to such allowances not only in standard financial accounting but also in accounting for income-tax purposes. (See p. 178, *infra*.) What these arguments overlook is the fact that, in unregulated business, accounting valuations do not impose legal restrictions on corporate earning power.

ception, the costs have lost significance because they no longer reflect, in terms of dollars of current purchasing power, the net financial sacrifice for which investors are still entitled to fair compensation under a cost-of-service principle of rate control. According to the second conception, these same costs have lost significance because they no longer reflect the current values of the assets devoted to the public service and hence because an allowed annual return thereon would not even crudely measure the annual service value or rental value of the assets to the consuming public. Thus, the first of these notions invokes an investor-sacrifice or cost-recoupment theory of a "fair return," whereas the second imports a somewhat roundabout version of a value-of-the-service standard.

In actual rate cases, these two significant factors in rate-base determination are more often than not intermixed instead of receiving separate recognition. But they can be distinguished readily for purposes of analysis. Consider, for example, the now uniformly accepted position that, even under an actual-cost type of rate base, a deduction should be made for the depreciation of depreciable assets. If the deduction is defended as fair to investors on the ground that it represents a portion of capital investment which has already been recouped by operating deductions charged, in effect, against former consumers, the defense rests on an investor-sacrifice or cost-recoupment principle of a fair return. But if the deduction is defended on the ground that the assets have "in fact" suffered physical or functional depreciation, regardless of the question whether or not the company has been compensated for this depreciation by previous charges for services, the standard of cost recoupment is made to give way to the standard of consumer benefit. This same distinction is revealed by current arguments as to whether or not the rate base (or, alternatively, the nominal rate of return) should contain a write-up for price inflation. If the write-up is designed to protect the corporate stockholders against the "confiscation" of a part of their original investment, measured in dollars of current purchasing power, it implies a cost-recoupment principle of a fair return. But if it is justified on the legally more orthodox ground that a rate base should reflect the current values of the corporate assets as a source of service to the consumers, it invokes a consumer-benefit or value-of-service principle of rate control. Nor is the choice between these two points of view one of merely

academic interest. For on this choice must depend the question what kind of an allowance should be made for price inflation, or even whether any allowance at all is justified in a given situation.

THE VICIOUS-CIRCLE OBJECTION TO A VALUE RATE BASE

For almost half a century, down to the time of the Second World War, the fair value principle of rate regulation, distinguished from any version of a cost principle, was held to control both state and Federal regulation of public utility and railroad rates in a series of Supreme Court decisions setting forth the principle and prescribing rules for its application in specific cases. Data on original costs of construction as well as on current reproduction costs were to be "considered" along with other data germane to an appraisal of property.[3] "But the "fact to be found" was "value" or "fair value" (the terms were used interchangeably) at the time of the rate case, just as in a valuation for tax purposes or in a determination of the proper compensation payable to the owner of property expropriated under the law of eminent domain. Indeed, the justices who wrote the ruling opinions in the rate cases sometimes made cross references to the tax and condemnation cases, thereby implying that the meaning of the term "value" remains unaffected by the purpose of the valuation.

Early in the history of the fair-value doctrine, critics of the Supreme Court's decisions objected that the "value" of public utility properties, though acceptable for purposes of tax assessment or as a measure of compensation for a compulsory taking, cannot qualify as a valid rate base since this value necessarily depends on the earnings that the company will be permitted to derive therefrom—the

[3] "We hold, however, that the basis of all calculations as to the reasonableness of rates to be charged by a corporation maintaining a highway under legislative sanction must be the fair value of the property being used by it for the convenience of the public. And in order to ascertain that value, the original cost of construction, the amount expended in permanent improvements, the amount or market value of its bonds and stocks, the present as compared with the original cost of construction, the probable earning capacity of the property under particular rates prescribed by statute, and the sum required to meet operating expenses, are all matters for consideration, and are to be given such weight as may be just and right in each case. We do not say that there may not be other matters to be regarded in estimating the value of the property. What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience. On the other hand, what the public is entitled to demand is that no more be exacted from it for the use of a public highway than the services rendered by it are reasonably worth." Smyth v. Ames, 169 U.S. 466, 546-547 (1898).

very question at issue in a rate case.[4] Any attempt to test the fairness of the rates by reference to a valuation of the properties is an attempt to reason in a circle, or, if you like, to put the cart before the horse. "Fair value" should therefore either be renounced as a measure of the rate base, or else given a special definition, which distinguishes its meaning from that assigned to it in other legal appraisals, presumably identifying it with some kind of cost or with some "fair" figure derived from cost. This vicious-circle argument against a fair-value rule was based squarely on the charge of logical fallacy. It did not rely on those "practical" objections to reproduction-cost methods of rate control so frequently voiced by critics of these methods.

This apparently unanswerable objection to a value rate base was repeated on many occasions, not only by economists but by legal commentators in the law reviews and elsewhere. As early as 1923, it was accepted by Justice Brandeis (Justice Holmes concurring) in his concurring opinion in the *Southwestern Bell Telephone* case,[5] which contained the famous phrase that "value is a word of many meanings." But although other justices, including Chief Justice Stone, later supported Justice Brandeis in this conclusion, the validity of the circular-reasoning argument was not overtly conceded by the Court itself until 1944, when Justice Douglas gave it express recognition in an opinion speaking for the Court.[6] One may there-

[4] This criticism was urged most vigorously, and perhaps with the most telling ultimate effect on judicial thinking, by Professor Robert L. Hale of the Columbia University Law School, who restated his position in his book, *Freedom through Law* (New York, 1952), Chap. 15, "The 'Fair Value' Fallacy in Rate-Making."

[5] Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U.S. 276, 289–312 (1923).

[6] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944). At page 601 Justice Douglas wrote: "Rate-making is indeed but one species of price-fixing. . . . The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. *Block v. Hirsh*, 256 U.S. 135, 155–157 (1921); *Nebbia v. New York*, 291 U.S. 502, 523–539 (1934) and cases cited. It does, however, indicate that 'fair value' is the end product of the process of rate-making not the starting point as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon 'fair value' when the value of the going enterprise depends on earnings under whatever rates may be anticipated."

In a footnote to the last quoted sentence, Justice Douglas cited Institutional Investors v. Chicago, M., St. P. & P. R. Co., 318 U.S. 523, 540 (1943), for a statement that the meaning of the word "value" is to be gathered "from the purpose for which a valuation is being made."

None of the dissenting opinions in the *Hope* case took issue with Justice Douglas's

fore raise the question how the Court, while under the influence of its older and more tradition-minded members, could have continued for so many years to deliver opinions and decisions in important rate cases without squarely facing a criticism of its underlying premise so plausible and, if valid, so utterly devastating.

To this question of judicial psychology and legal reasoning no complete answer will be attempted here. But a partial answer lies in the Court's success in sidestepping an embarrassing and difficult question of substantive law by resort to rulings on evidence that go a certain distance, at least, toward a recognition of the special character of a so-called valuation for rate-making purposes. Thus, in th[illegible] (later Chief Justice) Hughes referred to vicious circularity as a reason for rejecting railroad-land valuations based indirectly on estimates of corporate earning power. And for similar reasons, the Court in this and other rate cases gave little if any attention to the market prices of railroad or public utility securities as reflecting the values of the underlying properties, despite a suggestion in *Smyth v. Ames* that these prices ought to be taken into account. In short, while the Court talked about value, and while some of its actual rulings were predicated on value concepts, the data on which it laid most emphasis as evidence or "elements" of value were records of actual costs or estimates of reproduction costs. The costs themselves, moreover, were not given that critical review of their relevance that a skilled appraiser would give to them if his interest were confined to their possible bearing on the value of a property, say, for the purposes of a loan by an insurance company.[8] On the contrary, the cost data seem to have been accepted in their own right, as an index of a value which was fair rather than as evidence of a value which, fair or unfair, actually existed.

In any event, the question why the Supreme Court waited so long

conclusion that "value of the property," in its usual sense, is disqualified as a rate base. On statutory rather than constitutional grounds, Justice Reed contended that the Federal Power Commission was under a duty to adhere to "traditional concepts of fair value and earnings." But even these concepts were those of a special rate-making value, the essentials of which, he believed, "had been worked out in fairness to investors and consumers by the time of the enactment of this Act" (the Natural Gas Act of 1938).

[7] 230 U.S. 352 (1913).

[8] *My Valuation of Property* (New York, 1937) discusses in detail the relevance of original costs and of replacement costs in proof of the value of property. See, especially, Chaps. 8 to 10.

before conceding, in language and not just in somewhat hazy rulings on evidence, that "fair value" for rate-making purposes must be given a special meaning in order to avoid the circular-reasoning fallacy, has become of historical interest only. It now seems generally agreed, at least by all experts, that a "fair-value" measure of the rate base is not the same thing as a "fair-value" standard in taxation, in the law of damages, or in most other legal appraisals.[9]

CAN VALUE BE DEFINED SO AS TO AVOID VICIOUS CIRCULARITY?

Impressed with the force of the vicious-circle argument, many writers have gone beyond the point of insisting that rate-making value must be given a special interpretation in order to qualify it as a plausible rate base. They have also asserted that the measure of a rate base is necessarily cost and not a value in *any* accurate sense. Consistently with this view, they have insisted that the familiar debates as to the merits of an actual-cost rate base versus a fair-value rate base should be converted into debates as to alternative standards of costs, including various types of replacement cost and various versions or modifications of actual cost. The whole philosophy of a fair-return standard of rate making, they have declared, is a cost-of-service philosophy. On no account, therefore, should it be compromised or confused by a backdoor introduction of value-of-service criteria of reasonable public utility rates in the guise of value standards of the rate base.

Offered as a sound, general approach to the determination of a

[9] But in litigated valuations, there has been a backwash into the tax and condemnation cases of concepts of "fair value" developed in the early rate cases. In the valuation of railroad properties, e.g., tax assessors have been prone to attach to estimates of reproduction costs, or to rate-case valuations derived from these costs, probative significance in disregard of the far lower commercial values of the properties as inferred from current stock and bond quotations or from capitalized earnings.

In the condemnation of private utility systems under programs of public ownership, a somewhat different situation has prevailed. Even in jurisdictions, such as New York State, which apply a net-investment or actual-cost standard of rate control, condemnation awards have been based largely on the much higher, reproduction-cost appraisals. As a result, the expropriation may become a source of large windfall profits to the investors in the private company. See Lewis Orgel, *Valuation under the Law of Eminent Domain*, 2d ed. (Charlottesville, Va., 1953), Chap. XVII. In order to remove or reduce this source of windfall profits, the New York State Legislature passed a law calling upon the Public Service Commission to certify to the condemnation appraisers the allowable amount of the rate base. I have been told, however, that the appraisers have actually paid but little attention to the certifications.

proper rate base, I believe that the above statement is valid. But the statement must be revised, not only for reasons of scientific accuracy but also for important reasons of practice. What it rightly asserts is that for practical reasons to be noted in the following chapters, "value of the property," in any definitive sense of the term "value," cannot qualify as an acceptable measure of the rate base. What it wrongly implies is that, in the determination of the rate base, cost factors must entirely supersede value factors since the latter factors are alleged to be completely ruled out by the vicious-circle fallacy.

In fact, however, these factors are not thereby completely ruled out—not even under a net-investment principle.[10] Thus, the general (though not uniformly applied) rule that the cost of property must disappear from the rate base whenever the property ceases to be of public service is a value principle: the cost is now ignored, even if it has not been recouped by previous charges for service, because the property has ceased to have any value for its intended use. And thus, the reluctance of a commission to include in the rate base the price paid for public utility plants in a transfer from one company to another company, as distinct from original construction cost, again imports a value concept in its choice of the one cost rather than the other. That is to say, the cost entitled to a fair return is the cost incurred for the public benefit, not the price paid to buy out other financial interests. Finally, the principles for the allowance of depreciation, both as an operating charge and as a deduction from cost new in rate-base determination, become hopelessly arbitrary unless they are related, however roughly, to the downward trend in the *values* of the depreciating fixed assets as they become older and more decrepit. In none of these situations, to be sure, does value supersede cost as a measure of the rate base. But in all of them, value factors either influence the choice of the relevant cost or else influence decisions as to the proper rates of amortization and dates of complete write-off.

The vanity of attempts to apply cost-of-service principles of rate

[10] That is, not ruled out under this principle in its modern interpretation. The only way to rule them out, or nearly out, would be to accept rigorously an "unrequited sacrifice" rule of a fair return—a rule under which a company would be permitted to charge such rates as would ultimately indemnify it for all outlays, whether for capital account or for operating expenses, but which would never permit it to receive more than full indemnity. Such a rule, in my opinion, would be utterly impractical.

control in complete disregard of value factors was recognized by Justice Jackson in his brilliant dissenting opinion in the *Hope Natural Gas* case,[11] in which he denied the applicability of the prudent-investment theory to the production phase, as distinct from the transmission phase, of the natural-gas business.

> The prudent investment theory [he wrote] has relative merits in fixing rates for a utility which creates its service merely by its investment. The amount and quality of service rendered by the usual utility will, at least roughly, be measured by the amount of capital it puts into the enterprise. But it has no rational application where there is no such relationship between investment and capacity to serve. . . . The service one renders to society in the gas business is measured by what he gets out of the ground, not by what he puts into it, and there is little more relation between the investment and the results than in a game of poker.

But if one admits, as I think one must, that the net-investment principle of rate control is workable only if it can be made to preserve some degree of correspondence between the amount of the investment and the value of the corporate assets, how can this admission be reconciled with the vicious-circle objection to a value rate base? The answer is that, for rate-making purposes, the values of the corporate assets must cease to be identified with their value as private property and hence as sources of income (or of cost saving) to the corporation or to its investors. Instead, the relevant values must refer to the potential values of the assets as instruments for the production of service *to the community of consumers.* If these assets were not only utterly essential for the performance of the service but also utterly irreplaceable, their value to the consumers would be set by whatever rates of charge for service the consumers would be willing to pay rather than go without—set, in short, by what the traffic would bear. But if the assets are replaceable, their potential value to the consuming public is limited by their replacement costs.

For practical purposes, we may define this "service value" of public utility assets in another way: as the value that these assets *would have* to the corporation *if* it were obliged to continue the rendition of the service at rates determined without reference to any principle of a fair return. Under this hypothesis, the assets are

[11] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 628 (1944). Quoted at p. 649.

worth to the company whatever amounts would indemnify it for their loss—a loss limited by the opportunity to replace the old assets with new assets, probably of a superior design.[12] Such a hypothesis may seem meaninglessly artificial. But either it or some similar hypothesis is necessary in order to avoid the vicious-circle difficulty. Otherwise, if a public service commission or an appellate court were to value a public utility plant, for rate-making purposes, either at an exorbitant value on the one hand or at a zero value on the other hand, its very action would tend to make its findings of value come true, given enough potential earning power to support the exorbitant valuation.

Needless to say, the indirect admission of value elements even into a net-investment program of rate control is a far cry from the acceptance of "value of the property" as the actual measure of the rate base. We therefore still face the question whether, under a service-value definition of the kind just suggested, the values of the corporate assets, as distinct from their costs, can qualify as a sound measure. This question, I suggest, requires two answers. The first is that the adoption of a value standard, thus construed, is not ruled out by the mere logic of the vicious-circle objection.[13] But the second is that, in actual practice, the application of such a standard would be hopelessly unfeasible. For it would require the acceptance of a replacement-cost-of-service principle of rate control.[14] Reasons for denying the feasibility of this principle will be stated in the following chapters.

THE CONFUSED MEANING OF "FAIR VALUE" IN ACTUAL RATE REGULATION

The somewhat "difficult" interpretation of "fair value" suggested in the preceding section is the one required by any attempt to observe the fundamental economic distinction between "value" and "cost" [15] in a valuation for rate-making purposes, while avoid-

[12] But the hypothesis must exclude from the valuation of the existing plant and equipment any allowance for a temporary value in excess of replacement cost based on the impossibility of immediate replacement.

[13] It does, however, pose some difficult conceptual problems raised by the question what required rate of output, and hence what required plant capacity, should be assumed for the purpose of the appraisal.

[14] See pp. 226–230, *infra*.

[15] The "fundamental economic distinction" is not that between cost and *market* value, since vendibility is not an essential attribute of value despite the jingle that "The worth of a thing is the price it will bring." Instead, the distinction is

ing the pitfall of the vicious-circle fallacy. But, although this conception of value is implicit in *some* of the Supreme Court's earlier rulings and comments on the measurement of the rate base, it is certainly inconsistent with others. A similar statement applies to the postwar rate cases in those jurisdictions which, for reasons of statute law or legal tradition, have continued to adhere to a fair-value rule. Any attempt to rationalize the findings of "fair value" in these cases along the lines just suggested would involve the attempt to substitute the philosophy of an economic theorist for the philosophy of a legal practitioner. While there is implicit in this latter philosophy the same general distinction between value and cost that has been set forth in the preceding paragraphs, the distinction has been far less sharply drawn, so that it fails to reveal those uncomfortable dilemmas presented by uncompromising alternatives.

What has just been said is stated more simply by the observation that, in actual practice as distinct from textbook theory, the "fair value" standard of rate control is an eclectic or compromise standard, which takes simultaneous account of conflicting measures on the ground that there is "something to be said" for each of them.[16]

between the actual or anticipated sacrifice involved in producing or acquiring any sought-for object, and the favorable importance or prizeworthiness of the object from whatever standpoint is accepted by the person making the valuation.

[16] This statement applies more clearly to some cases or to some jurisdictions than to others. At one time the Supreme Court, under the influence of Justice Butler, seems to have come close to the point of identifying "fair value" with estimates of reproduction cost of a substantially identical plant minus deductions for opinion estimates of "observed depreciation": McCardle v. Indianapolis Water Co., 272 U.S. 400 (1926), a position from which it receded in later cases. See my *Valuation of Property*, Chap. 31. In Ohio and perhaps in a few other states, the highest state courts have, in effect, interpreted the governing statutes as making depreciated reproduction cost "the value for the purposes of the case." But the more usual position is that original cost and reproduction cost, along with still other data, are "elements to be considered." The only definite requirement about reproduction cost is that it be "given some weight." See, e.g., Diamond State Telegraph Company, July 23, 1954 (Delaware Supreme Court), 54 *Public Utilities Fortnightly* 393 (Sept. 30, 1954). In New York State, the Court of Appeals has recently interpreted a statute governing transportation and telephone rates (but not electric and gas rates) as requiring a commission to take account of data on replacement cost. But it has denied that such data are controlling. N.Y. Telephone Co. v. Public Service Commission, 309 N.Y. 569 (1956). Several years ago, the Illinois Supreme Court, reversing the Illinois Commerce Commission, held that a public utility is entitled to a "fair-value" rate base which gives consideration to replacement costs. Illinois Bell Telephone Co. v. Illinois Commerce Commission, 414 Ill. 275 (1953). But the Commission's subsequent allowances for "values" in excess of depreciated original costs have varied for reasons not made explicit in the opinions.

But the basis of the compromise is itself usually left indefinite, with the result that even the expert, familiar with the decision by a particular commission in the last rate case, cannot predict with confidence how the conflicting data will be resolved by the same commission in a later case.

Is this eclectic standard of rate control good or bad? Persons who like it praise it for its flexibility and for its refusal to be bound by codified rules that may prove embarrassing at later times.[17] Persons who dislike it condemn it for its confusion, its indeterminacy, and its invitation to endless controversy between corporate or investor interests and consumer interests. For reasons suggested in the next two chapters,[18] my own convictions support the latter position.

[17] Persons who object to *any* fair-return limitations on public utility earnings naturally tend to prefer a "fair-value" rate base as the lesser evil because of its very flexibility. This viewpoint was voiced by the late President Hadley of Yale, an eminent economist, in testimony before the New York Commission on the Revision of the Public Service Commission Laws, *Hearings* (Albany, 1930), II, 728–729. Asked whether, if compelled to choose, he would take a rate-making "valuation" based on original cost, or one based on reproduction cost, he replied: "I would select reproduction cost every time." One reason for this choice, he continued, is that "reproduction cost is not an exact thing. You don't know what it is. . . . Now, on the record of uncertainty—the inevitable uncertainty, it seems to me as [is?] an important value in the reproduction cost because the Commission is left to decide things for itself, and the Commissions of the Western States are in general well-meaning men who will try not to do a thing that will hurt business. I think that is the saving clause in the reproduction system, the fact that it is frankly a makeshift, the fact that the results are almost necessarily guesswork, and therefore the Commission simply uses it as a general guide to prevent grave abuses and decides the cases partly at least by its good business sense as far as the law will permit it." While President Hadley was here replying to a question about the relative merits of original cost and reproduction cost as measures of the rate base, his grounds for preferring the latter apply a fortiori to an undefined and flexible "fair-value" rate base.

[18] I have presented these reasons in much more detail, and by reference to the actual history of attempts to apply the fair-value rule, in a minority report of a commission appointed to investigate the alleged breakdown of regulation in New York State. Cited in footnote 1 of this chapter.

XII

THE RATE BASE: ACTUAL COST WITH OR WITHOUT ADJUSTMENT FOR PRICE-LEVEL CHANGES

As indicated in the preceding chapter, the primary economic issue in rate-base determination concerns the question whether or to what extent the rate base should comport with an investor-sacrifice or actual-cost principle of rate control as against a present-value or replacement-cost principle. We now turn to the merits of this question. The present chapter and the one immediately following will discuss the nature and philosophy of an actual-cost rate base, whereas Chapter XIV will discuss the nature and philosophy of a replacement-cost or present-value rate base.

But before comparing these two different principles of rate control, we must again note the confusion imported into the comparison by the factor of general price inflation, which became serious following the Second World War. This inflation has created a wide gap between the recorded depreciated costs or book values of public utility assets and the current service values of these assets as based on their prevailing replacement costs. But this same inflation has also given rise to the plausible contention that, even under a strict actual-cost or cost-recoupment principle of rate control, either the rate base or else the allowed rate of return should be enhanced in order to make the capital costs incurred in early years commensurate with the money income to be allowed on these costs in later years.

The important point to note here is the vital distinction between these two objections to an unmodified original-cost type of rate base. Only the first objection calls for the rejection of actual-cost

principle of rate making in favor of a present-value or reproduction-cost principle. The second objection calls merely for a restatement of original costs in the very interest of the cost-recoupment principle. The practical importance of this distinction can be illustrated by an extreme, but by no means impossible, situation in which the (depreciated) replacement cost of the plant and equipment of a particular company has fallen below (depreciated) original cost even during a period of rising general price levels.[1] Here, the acceptance of a rate base *lower* than original cost would be required under a present-value standard of rate making, whereas the acceptance of a rate base *higher* than original cost would be required under a stabilized-dollar version of an actual-cost standard.

By way of minimizing the confusion resulting from the twofold distinction (a) between an actual-cost and a present-value rate base, and (b) between an unadjusted actual-cost rate base and an adjusted actual-cost rate base, these chapters will first discuss the relative merits of the former alternatives under the simplifying assumption of a stable general price level. But since this assumption is not realistic under conditions prevailing today, proposals to make allowance for price inflation or deflation even under an actual-cost rule of rate making will be considered briefly toward the end of this chapter and will receive extended discussion in Chapter XV, "The Fair Rate of Return."

GENERAL NATURE OF THE ACTUAL-COST STANDARD

In its modern form, the actual-cost or net-investment standard may be defined as one which measures the rate base by a summation of the actual legitimate costs of plant and equipment devoted to the public service (including or plus allowances for interest during construction), with appropriate deductions for accrued deprecia-

[1] Justice Brandeis called attention to this possibility in his concurring opinion in Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U.S. 276, 289–312 (1923). Referring to the use of reproduction-cost standards of rate making in the 1880s and the early part of the twentieth century, he wrote: "At first reproduction cost was welcomed by commissions as evidence of present value. Perhaps it was because the estimates then indicated values lower than the actual cost of installation; for even after the price level had begun to rise, improved machinery and new devices tended for some years to reduce construction costs." P. 299.

tion and with reasonable allowances for working capital.[2] But this definition is obviously indefinite and is even subject to minor violations in actual practice. In consequence, the amount of the rate base may be in dispute even among parties all of whom would accept an actual-cost principle of rate control.[3]

A full and critical review of all of these disputes would fill a large volume and is beyond the scope of a book so largely limited to the basic criteria of reasonable rates. But at least four problems of application are of special theoretical interest, and they will be discussed briefly if only to give to the type of rate base here under review enough definiteness to permit of a comparison of its economic merits with those of a present-value rate base. These problems concern (a) the choice between "original" cost and subsequent "acquisition" cost, (b) the allowance for interest during construction, (c) the inclusion or exclusion of capital outlays previously charged off as operating expenses under earlier accounting conventions, and—most important of all—(d) the allowances for depreciation, both as an annual operating charge and as a deduction from cost new in the measurement of the rate base.

[2] This definition conforms to general regulatory usage in recent years. The standard has been called by various names, used sometimes interchangeably, sometimes with distinctions. "Original cost," in public-utility accounting, has now become a term of art. It means the cost of an asset when first devoted to the public service rather than the cost to a transferee company. "Historical cost," though once used in special senses, has now become a term for *any* cost which, having already been incurred, has now become a "matter of history." The "prudent-investment" or "net-investment" principle seems now to be used interchangeably with the "actual-cost" principle despite earlier suggested distinctions. "Prudent" imports the requirement that the investment, in order to gain recognition in the rate base, must have been prudently incurred in the light of foresight rather than of hindsight. See Justice Brandeis's comment on this point in his concurring opinion in Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, *supra*, note 1. "Net" means net of deductions either for capital investments already recouped from revenues charged to depreciation or amortization, or else for asset depreciation already sustained—an obvious ambiguity. "Investment" refers to the capital funds contributed by the company to the public service as distinct from the current values of the assets acquired by these funds.

[3] A dispute of this nature was the basis of Justice Reed's dissent from the decision of the Supreme Court in Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 620–624 (1944). While Justice Reed phrased his dissent as one in support of the traditional fair-value standard, he raised no objection to the Federal Power Commission's refusal to recognize replacement costs rather than original costs. Instead, he declined to go along with the Court in sustaining the Commission's rate order despite its refusal to include, as a legitimate item of actual capital cost, the $17,000,000 of well-drilling expenses and other outlays that the company had previously "conservatively" charged to operating expenses under its earlier accounting practices. See pp. 180–183, *infra*.

ORIGINAL CONSTRUCTION COST VERSUS SUBSEQUENT ACQUISITION COST

Let us assume, as we must under the rate-making standard now before us, that the rate base of a company which seeks an increase in its rates is to be set at the depreciated actual costs of its properties (with adequate allowances for working capital), regardless of the question whether or not these costs reflect the present values of the assets. But let us also assume that the properties of the present company, while constructed at a cost of $60,000,000, were later acquired by purchase from the original company in an arms' length transaction for a cash price of $75,000,000—a price paid in view of then anticipated earnings, and despite the existence on the vendor company's books of a depreciation reserve of $10,000,000 at the time of the transfer. Under this assumption, which actual-cost figure should govern the rate base—the $50,000,000 depreciated construction cost, or the $75,000,000 acquisition cost?[4] A mere resort to the definition of "actual cost" will not supply the answer, nor would the substitution of terms such as "historical cost" or "original cost" (in its traditional, nontechnical sense). For the $60,000,000 construction cost and the $75,000,000 acquisition cost are equally actual, equally historical, and equally original (to the one company or to the other).

Problems of this nature—usually complicated, however, by transactions between affiliated interests and by noncash purchases or mergers—were faced on a wide scale by the regulating commissions in the 1930s and 1940s, when, after inexcusable delays, they finally

[4] I have discussed this issue at greater length in testimony offered on behalf of an industrial consumer in a case before the Maryland Public Service Commission involving rates charged by the Consolidated Gas and Electric Company (now the Baltimore Gas & Electric Company), testimony later partly published under the title "Original Cost as a Rate Base," 20 *Accounting Review* 441–447 (1945). There is a considerable literature on the accounting aspects of the subject with incidental reference to rate making. For a discussion of the subject from the standpoint of the accounting profession, see James L. Dohr, "Power Price Fixing," a series of articles in the June, July, and August issues of the *Journal of Accountancy* for 1945. For sharply opposing points of view on rate-making aspects, see Homer Kripke, "A Case Study in the Relationship of Law and Accounting; Uniform Accounts 100.5 and 107," 57 *Harvard Law Review* 433–478 and 693–727 (1944); and William A. Paton, "Accounting Policies of the Federal Power Commission—a Critique," 77 *Journal of Accountancy* 432–460 (1944). Finally, see Federal Power Commission, *Report on the Reclassification and Original Cost of Electric Plant of Public Utilities and Licensees* (Washington, D.C., 1950).

undertook to secure a wholesale reorganization of operating company accounts following the financial and moral breakdown of the great holding-company systems. Led by the Federal Power Commission and by the more aggressive state commissions, the country's regulating agencies have come close to a settlement of the *accounting* disposition of these dual costs. The basic property records are now kept at an "original cost" expressly defined as cost to the person (corporate or natural) first devoting the property to the public service. For the most part, this means actual construction costs. But the acquisition costs to the present accounting company are also to be recorded, and the difference between the two figures (with adjustments for depreciation, the provisions for which are not clear, at least not to me) is to be charged (if acquisition cost is higher) or credited (if lower) to a special Acquisition-Adjustment Account —an account subject to later disposition, usually by fairly rapid amortization in the case of a debit entry.

This accounting disposition of the problem, however, has not been conclusive for rate-making purposes; for the question remains whether the rate base must be governed entirely by what is now called the "original cost." There is the further question whether any excess in acquisition cost, even if included in the rate base, should be subject to standard rules of depreciation or whether it should be subject to special types of amortization. These problems are not easy ones, and only their barest elements will be discussed here. But the elements are important, and they have not always been recognized in the partisan debates on the issue.

Our hypothetical case presents the problem in its simplest form in assuming not only that the $75,000,000 transfer price was paid in cash but also that it represented an arms' length transaction between strangers. We may add the further assumption that, viewed as a business transaction, the price paid for the properties by the present company was not extravagant in the light of the generous earnings that might have been anticipated under the influence of the then prevailing rules and practices of rate regulation. This being the situation, what are the merits of a contention by the present company that, even under an actual-cost rule of rate making, it must be permitted to enjoy a "fair" rate of return on the cost incurred by it rather than on the cost to the vendor company?

Subject to a qualification to be noted presently, I think that this

contention is without merit and that the relevant cost datum is the $50,000,000 depreciated original cost. True, the $75,000,000 transfer price was also an actual cost—in fact, the only cost actually incurred by "the present accounting company." But this cost does not represent a contribution of capital to the public service. Instead, it represents a mere purchase by the present company of whatever legal interests in the properties were possessed by the vendor. Even under an actual-cost standard of rate control, investors are not compensated for *buying* utility enterprises from their previous owners any more than they are compensated for the prices at which they may have bought public utility securities on the stock market. Instead, they are compensated for devoting capital to the public service. The only capital so devoted was the original $60,000,000, of which $10,000,000 has already been recouped from revenues earmarked as allowances for depreciation. The present company's claim is therefore merely a claim to be standing in the vendor company's shoes. This conclusion would be equally valid if the figures were reversed and if the acquisition cost were to fall $25,000,000 short of the depreciated original cost.[5]

The foregoing conclusion is subject to revision if the transfer of the properties to their present corporate owner was an essential, or at least a desirable, part of a program of integration, justified in the public interest for the purpose of securing operating efficiencies that would offset any unavoidable excess in acquisition costs over original costs. In such a situation, and in view of the failure of our prevailing public utility laws to provide for compulsory mergers, a claim by the present company that its purchase of the acquired properties was, in effect, a devotion of capital to the public service, cannot be dismissed as without merit. On the contrary, the

[5] The unfairness, not to say the absurdity, of a uniform rule permitting a transferee of a utility plant to claim his purchase price as a measure of rate-making investment was noted by Judge Learned Hand, speaking for the Circuit Court of Appeals for the Second Circuit in an accounting case involving the valuation of property acquired by the present company through a merger of two predecessors. If the rate base, he said, were to be set at the price paid by the new purchaser, then "the builder who does not sell is confined for his base to his original cost; he who sells can assure the buyer that he may use as a base whatever he pays in good faith. If the builder can persuade the buyer to pay more than the original cost the difference becomes a part of the base and the public must pay rates computed upon the excess. Surely this is a most undesirable distinction." Niagara Falls Power Co. v. Federal Power Commission, 137 F (2d) 787, 793 (1943).

company may properly receive an opportunity to prove its claim, although difficulties of proof are serious. Proof should be more readily adduced with respect to mergers or acquisitions, the terms of which have first been cleared with the regulating commission after a full public hearing and investigation.

There remains the question whether any excess in acquisition cost over original cost, if found includible in the rate base, should later be subject to depreciation or amortization through cost-recoupment allowances charged to annual operating expenses, or whether any required amortization should be cleared through the income statement "below the line" (of operating deductions), thereby taking place at the expense of the corporate stockholders. At least for purposes of accounting, the latter alternative has been chosen by the Federal Power Commission. As to the correlative treatment of the problem for rate-making purposes, something will be said in the next chapter, on depreciation.

INTEREST DURING CONSTRUCTION

In a rate base measured by actual cost, there would be no occasion for an allowance for interest during construction if capital devoted by the company to the public service were given an opportunity to enjoy a "fair rate of return" from the very moment of its investment.[6] Some commissions, indeed, have granted this opportunity by including directly in the rate base amounts expended on work still under construction and hence not yet rendering public service. But unless these amounts are relatively small compared to the investments in completed plant, their immediate inclusion in the rate base would be a questionable departure from the general principle that the public utility consumers of any given year should pay a return only on the costs of those assets that are performing for them a useful service. In any event, the general practice is to withhold from the rate base major plant construction costs until the plant itself has become part of the "used and useful" property.

[6] This section summarizes the conclusions of a report, dated Aug. 25, 1952, entitled "Interest during Construction" that I submitted to Messrs. Arthur Andersen & Co., Public Accountants. The report was largely a commentary on points raised by the Federal Power Commission in its opinion in the *Northern Natural Gas* case, decided June 10, 1952 (Docket Nos. G-1382, G-1533, G-1607). It was included as part of a brochure by Arthur Andersen & Company entitled "Principles Underlying the Capitalization of Interest During Construction," dated March 1, 1953.

As long as this withholding practice exists, as I think it should, at least in times of rapid plant expansion, there arises a need for some rate-making provision whereby the company may eventually receive an adequate compensation for its advance commitment of capital. The standard provision of this nature, and the one that I believe most satisfactory, is that of a "computed" allowance for interest during construction—an allowance not restricted to the contract interest, if any, that the company may pay on loans designed to finance the construction work. "Interest during construction" is not a happy term for this allowance; but it has become traditional, and no clever phrasemaker has yet offered a convenient substitute.

So far as I know, the propriety of some allowance of this type as a component of the rate base has been conceded by all commissions. But, several years ago, the standard form of its recognition was challenged by the staff members of the Federal Power Commission, who insisted that the allowed rates of "interest" should be limited to the low contract rates payable on borrowed funds instead of being set at rates, such as 5 or 6 per cent, typical of the usual "fair rate of return." The staff even intimated that, on grounds of "accounting principles," the compensation payable to companies for their commitment of capital in advance of any claim to a fair return should take the form of later enhancements in the allowed rate of return instead of taking the form of enhancements in the rate base. The relevant "accounting principles" were found to lie in the strict adherence of orthodox fixed-asset accounting to the principle of cost. While the failure of a company to earn any return on capital embodied in work in progress was conceded to justify more liberal later allowances of opportunities to make a profit, it was held not to constitute a "cost" in an accurate sense, at least not in any sense recognized in financial accounting.

This attempt by the Commission's experts to judge the merits of a practical rule of rate control by an appeal to "general principles of accounting" gave some spokesmen for the utility companies a dose of their own medicine.[7] But to me, at least, it seems quite

[7] I refer particularly to attempts by expert witnesses for public utility companies to invoke "accepted principles of accounting" in support of the recognition of acquisition costs rather than of "aboriginal costs" as components of the rate base. Both sides in rate-case disputes have a tendency to find these "accepted principles" relevant when, but only when, they comport with whatever rules of rate making they favor in the case at bar.

unconvincing, since it has little or no bearing on the really important practical question—whether the provisions for compensation on capital that has been tied up in work under construction should take the form of a rate-base enhancement or of a rate-of-return enhancement. Here, I think standard procedure is wise in accepting the former alternative, and for reasons quite apart from the academic question whether the allowance of interest during construction is regarded as a recordation of an actual cost, or alternatively as the allowance of a credit to the corporation for a temporary denial of opportunity to earn a return on cost.[8]

As to the question whether the allowance for interest during construction should be based on percentage rates approximating contract interest on secure loans, or whether it should be based on a higher rate approximating an accepted "fair rate of return," the answer should depend on the answer to the further question, Which comes closer to reflecting the "time discount" that the investment market places on investments on which the anticipated return is subject to a material delay, as compared to investments that promise immediate income? To the best of my knowledge, no thoroughgoing study of this problem has ever been made. But the well-recognized market preference for early, and hence less uncertain, realization strongly suggests a time discount not lower than that reflected by a standard "fair rate of return."

RECLASSIFICATION PROBLEMS IN STATEMENTS OF ORIGINAL COSTS

One difficult problem in the "interpretation" of a net-investment standard of rate making may be illustrated by the most famous example of its occurrence in the history of American public utility regulation: the example of the *Hope Natural Gas* case of 1944.[9] I mention it here as raising the question whether a capital cost, however legitimately incurred, may properly be excluded from an

[8] In my opinion, the latter interpretation is correct, since a failure to earn any return on the cost of a capital asset is not in itself a cost in a strict sense. As to the proposal to disallow rate-base enhancements in favor of a more liberal "fair rate of return," this would impose upon those persons who must calculate the proper percentage rate the obligation of attempting to do indirectly, and without benefit of adequate accounting data, what the overt allowances for interest during construction do directly and systematically. Anyone who has faced the difficult problem of establishing a fair rate of return or of estimating "cost of capital" can hardly welcome a change in the rules of rate-base determination that would needlessly add to his difficulties.

[9] Federal Power Commission v. Hope Natural Gas Co. 320 U.S. 591 (1944).

actual-cost rate base on the ground that the company has already recouped the outlay from earlier customers, or at least has enjoyed an adequate opportunity to secure recoupment.

The reader may recall that, in the *Hope* case, the Supreme Court, expressly renouncing the fair-value doctrine in *Smyth v. Ames*, upheld the Federal Power Commission in its acceptance of original-cost data to the exclusion of replacement-cost estimates in the measurement of a rate base. And on this particular issue there were no dissents from the majority opinion by Justice Douglas. But in its summation of original costs, the Commission had excluded approximately $17,000,000 of outlays, mostly in the nature of well-drilling expenditures, which the Commission's own accounting rules would recognize as capital outlays but which the company, following the earlier practices of the natural-gas industry, had previously charged off as operating expenses. In reply to the company's argument that, regardless of their accounting disposition, these outlays represented actual costs of properties still used and useful in the public service, the Commission insisted that the costs had already been recouped, under the guise of current operating expenses, by charges for service imposed upon the earlier customers.[10] Hence, a later reclassification of the expenditures as items of capital investment, entitled to future compensation, was deemed improper, as involving the vice of double-counting against consumers.

Justice Douglas's opinion did not pass directly on the merits of this issue, since it found the Commission's rate order to be fair regardless of possible infirmities in the technique of rate-base determination.[11] But two of the dissenting opinions (those by Justices Reed and Jackson) took sharp issue on this point; and both the

[10] In support of its contention that the outlays had already been recouped, the Commission stated that, during the period (1898 to 1923) for which the company sought to reaccount for its plant costs, the average rate of earnings on its average invested capital (capital stock and surplus) was more than 15 per cent. But for reasons stated in pp. 210–212, *infra*, the enjoyment of excess earnings does not in itself prove capital-cost recoupment or return of capital. Justice Jackson's dissenting opinion is good on this point.

[11] Referring to his conclusion that the Commission's rate order was fair when judged by practical standards of corporate financial requirement and of reward for risks assumed, Justice Douglas declared: "In view of this disposition of the controversy we need not stop to inquire whether the failure of the Commission to add the $17,000,000 of well-drilling and other costs to the rate base was consistent with the prudent-investment theory as developed and applied in particular cases." 320 U.S. 591 at 605–606 (1944).

legal and the practical merits of the issue remain unsettled to the present day. What made this issue, as presented in the *Hope* case, so difficult was that it raised the frustrating problem of the fairness of retroactive regulation, applied to a company hitherto subject to no Federal regulation and apparently to only limited state regulation. If the Hope Company's earlier practice of charging well-drilling outlays to operating expenses had been sanctioned by the Federal Power Commission and had been accepted by the Commission as a basis on which to account for capital costs and operating costs in the determination of reasonable rates, its later attempt to restore the outlays to its capital accounts would clearly have been indefensible on the ground of double-counting.[12] But such was not the situation in the *Hope* case, since the company had ceased "expensing" its well-drilling costs in 1923, five years before the passage of the Natural Gas Act. One may therefore seriously doubt whether its superseded accounting practices had actually resulted in the imposition upon earlier customers of higher charges than would have been imposed even if the later, superior form of accounting had been followed right from the beginning.[13] In view of this doubt, one may question the fairness of the Commission's refusal to permit the retroactive reclassification of the well-drilling expenses, especially so since the very imposition of a net-investment standard of rate control on a concededly well-managed company which had long been free from any such strict regulation was

[12] A situation like that just mentioned has applied to reclassification problems raised in other rate cases. Thus, in Illinois Commerce Commission v. Commonwealth Edison Company, April 13, 1933, 15 P.U.R. (N.S.) 404, the Commission disallowed, as part of the "true" cost of plant and equipment, approximately $40,000,000 of overhead costs incurred between 1908 and 1934 which, though otherwise properly included as a part of plant construction costs, had been treated as operating expenses by the company itself. "It would be improper," said the Commission, "to allow the company to capitalize on its books now any items (apart, of course, from mere accounting errors) which were charged to operating expenses and so reported in reports to the Commission for the period from July 1, 1913 to the present." To the best of my knowledge, these disallowed overhead costs have never been restored to the Commonwealth Edison Company's plant accounts, with the result that the book costs of the company's present properties are said to understate their original costs.

[13] But the Federal Power Commission had some basis for an affirmative answer to this question because of the fact that, in a 1921 rate case, seven years prior to the passage of the (Federal) Natural Gas Act, the Public Service Commission of West Virginia had allowed the Hope Company's claim that its well-drilling expenses should be included among its current operating expenses. As of 1923 and thereafter, the same state commission required Hope to charge future expenses of this type to capital account.

itself a rugged—though, in my opinion, a justified—innovation in public policy.

Aside, however, from questions of retroactive fairness, I believe that the Federal Power Commission was warranted in attaching far more weight to the manner in which a public utility company has accounted for its capital outlays than would seem to have been deemed proper by Justice Jackson in his dissenting opinion warning against the tendency "to make a fetish of mere accounting." The very nature of an actual-cost or net-investment standard of rate making is such as to impose the necessity of making somewhat arbitrary, conventional distinctions between operating costs and capital costs.[14] In view of this necessity, rate regulation wisely places a high premium on consistency of accounting practice, for reasons analogous to those which also dictate adherence to reasonable consistency in income-tax accounting.

THE DEDUCTION FOR ACCRUED DEPRECIATION

Up to a time ending, perhaps, in the middle of the 1930s, writers and commissions were not in agreement as to the propriety of *any* deductions for depreciation in the measurement of a rate base derived from actual costs rather than from estimates of current replacement costs. Some writers argued that the deduction from cost new of an allowance for the depreciation ("decline in value") of the corporate assets imports into a cost rate base a value element which has no business there.

Today, this issue is closed as a matter of accepted practice. Actual cost, no less than replacement cost, is now recognized as subject to deductions for depreciation. But the question what constitutes a proper allowance for depreciation, both as an annual operating charge and as a negative component of the rate base, is still one of the most difficult and most controversial problems of rate-base determination under the actual-cost principle. Because

[14] The special importance of these somewhat arbitrary distinctions between capital outlays and operating costs lies in the fact that, even under an actual-cost standard of rate making in its accepted form, public utility companies may not seek restitution from later consumers for deficiencies in revenues secured from earlier consumers; nor, on the other hand, may realized earnings in excess of an established "fair rate of return" be credited to the rate base as a return of capital. See Professor R. L. Hale's significant treatment of this point in his article on "Utility Regulation in the Light of the Hope Natural Gas Case," 44 *Columbia Law Review* 488–530 at 503–520 (1944).

of its involved character, its discussion will be reserved for the next chapter. But provisionally, the deduction for depreciation, under the actual-cost standard, may be defined as a deduction for that part of the capital costs of the fixed assets that has already been, or should have been, recouped from past revenues.

THE TWO MAJOR ADVANTAGES OF AN ACTUAL-COST RATE BASE

In introducing the chapters of this book on "reasonable-return" standards of rate control, Chapter X distinguished five different goals of rate-making policy by reference to which one might judge the relative merits, alike of alternative measures of the rate base and of alternative measures of a fair-percentage rate of return. An exhaustive study might now attempt to apply first the one test and then each of the others to an appraisal of the claims on behalf of an actual-cost rate base versus the claims on behalf of a reproduction-cost or present-value rate base. But this procedure would be needlessly confusing, since it would involve endless detail which would draw attention away from the primary issues involved in the controversy.

Stated briefly, the claimed superiority of an actual-cost standard of rate making lies in the two, closely related, virtues of administrative feasibility and of capital-attracting or credit-maintaining efficiency.[15] Also stated briefly, the claimed superiority of a re-

[15] The great classic in defense of the "prudent-investment" principle of rate making, which remains unrivaled by the later literature despite a number of statements whose validity would now be challenged, is Justice Brandeis's minority opinion (concurring as to results) in Southwestern Bell Telephone Co. v. Public Service Commission, 262 U.S. 276, 290 (1923). "The thing devoted by the investor to the public use," he declared, "is not specific property, tangible or intangible, but capital embarked in the enterprise." The Justice found the legal basis for this position in what may be called a quasi-agency conception of a public utility company. "The investor agrees, by embarking capital in a utility, that its charges to the public shall be reasonable. His company is the substitute for the state in the performance of the public service, *thus becoming a public servant.*" [My italics.] Perhaps because the issue was not raised by the contesting parties, the opinion did not consider directly the question whether even the amount of "the capital embarked in the enterprise," as distinct from the fair value of the corporate assets, should be stated in terms of dollars of currently equivalent purchasing power. But Justice Brandeis minimized the weight of the price-inflation argument for a fair-value rate base by suggesting the likelihood of later price deflations, such as had previously occurred in American history.

The Supreme Court's later renunciation of the fair-value rule in the *Hope* case, while going far toward accepting Justice Brandeis's economic and practical de-

production-cost or present-value standard lies in its supposed performance of the function of a competitive price in controlling demand for public utility services so as to prevent wasteful overuse on the one hand and inadequate use on the other hand. Postponing the latter claim for the chapter on the replacement-cost principle, we may now consider the affirmative case in favor of actual cost.

1. SUPERIOR ADMINISTRATIVE FEASIBILITY

No program of rate regulation is self-executing. On the contrary, any such program must be administered; and the responsibility for its effective administration falls on a state or Federal public service commission. Among the most important virtues of an actual-cost rate is that of relative ease of administration in terms of speedier disposition of rate cases, definiteness of decision, and minimum expense to all parties and to the commission.[16] It is a virtue reluctantly conceded even by supporters of a "fair-value" rate base. To be sure, these supporters have rightly noted that even an actual-cost standard is by no means free from serious controversy—a controversy likely to shift from rate-base issues to disputes about the "fair" rate of return. But since the fair-value standard, in its currently accepted version, accepts both actual-cost and replacement-cost data as so-called "elements of value," its acceptance merely adds new controversies. Moreover, as commissions and courts get more experience with the application of actual-cost rules of rate control, there is good reason to hope for a material reduction in sources for disagreement.

What has just been said is not meant to imply that, in a jurisdiction operating under a fair-value rule, where a rate-level case re-

fense of the alternative "prudent-investment" rate base, did not follow his proposal to substitute an investment standard for a value standard as a test of constitutionally "confiscatory" rates. Instead, the Court seems to have left open the question what, if any, rate-making restrictions may be imposed upon a legislature or a public service commission by the due-process clause of the Constitution of the United States. On this point see the separate opinion of Justices Black and Murphy. See also a later decision, Market Street Ry. v. Railroad Commission, 324 U.S. 548 (1945), in which the Court declined to upset a California commission rate order which fixed a rate base below actual cost minus conventional depreciation.

[16] This great "practical" advantage of an actual-cost rate base over an appraised-value rate base was developed in much more detail, and with historical examples, in the Minority Report of the New York State Commission on the Revision of the Public Service Commissions Law (1930), a report in which I participated as a member of the Commission. See Chap. IX, note 2.

quires an expensive engineering reappraisal of plant and equipment, the sum total of rate cases held in any one year will necessarily impose upon commissions, and upon the disputants, more trouble and expense than would be imposed under an actual-cost rule. Indeed, the contrary situation is likely to prevail; for the difficulties of an engineering valuation are so great that they discourage commissions and parties from engaging in rate cases, with resulting serious delays in needed rate revisions.

2. GREATER EFFECTIVENESS IN CREDIT MAINTENANCE

In hearings before public service commissions, critics of the actual-cost principle have sometimes asserted that even its defenders can claim nothing in its favor save the "practical" virtue of convenient administration. In fact, however, this assertion is false. The primary advantage claimed for the principle is that of superior efficiency in enabling public utility companies to maintain their credit and to secure needed new capital on terms most favorable to the consuming public. This claim rests on considerations of corporation finance, which demand the maintenance of a sound relationship between corporate earning power and the annual revenue requirements imposed by fixed and quasi-fixed charges on outstanding securities. Since these charges depend on the amounts of outstanding bonds and preferred stock, they are far more closely related to the capital actually invested in the corporate properties than to the current reconstruction costs or present values of the corporate assets.

For reasons already noted in Chapters IV and VI, the basic criticism of an actual-cost principle from the standpoint of economic theory runs to the effect that historical costs are sunk costs and hence that they should be disregarded in price fixing, since they fail to set up a proper barrier by which to discourage excessive consumption of public utility service while permitting all worth-while consumption. This is a weighty criticism, and one that will again receive attention in Chapter XIV. But even if valid, it would not belie the offsetting superiority of an actual-cost standard when judged by the quite different criterion of capital-attracting effectiveness. For, although actual costs will have become sunk costs at the time of a rate case, they are not sunk costs when first incurred, and it is at this time that investors must balance, *ex ante*, the expected future return on any proposed investment against the presently required outlay of capital. In other words, what induces investment is the expectation of a return on (or return of) costs that will have become sunk as soon as the investors have made their commitments. Whatever scheme of rate regulation will put investors in a position to draw this balance between present outlay and anticipated future return with the most confidence is the scheme most likely to permit a well-managed company to maintain sound financial health at a minimum "cost of capital" to the consumers.

So clearly is the security structure of modern public utility companies geared to an assumed earning power based on sunk capital investments that I very much doubt whether a so-called "fair-value" rate base would win that widespread favor which it still enjoys within the industry and among professional investors were it not for the conviction that it will always remain, as it is today, the higher rate base or, at least, that it will never fall below a rate base measured by depreciated actual cost.[17] This conviction rests on the belief that, because of the political power of the labor unions combined with other inflationary influences, the long-run trend of prices will continue upward, periods of business recession constituting at most temporary interruptions or slight reversals of the general trend.

THE DANGER THAT ACTUAL COST WILL BE REJECTED IF HIGHER THAN REPRODUCTION COST

Even some supporters of a reproduction-cost principle of rate control have conceded that the actual-cost standard has the advantage of greater effectiveness in credit maintenance and hence in capital-attracting efficiency. Their preference for reproduction cost lies in other directions. But two objections to an actual-cost standard must be noted in this chapter since they challenge actual-cost advocates on their own ground of credit maintenance. The first objection is that, during a period of price inflation, equity capital

[17] The tendency of public utility spokesmen to support the fair-value principle only when it leads to the establishment of a rate base at least as high as one derived from actual costs was noted by Justice Brandeis in his separate opinion in the *Southwestern Bell Telephone* case, *supra*, note 15.

cannot be secured in sufficient amounts under any system of rate making which fails to protect stockholders against further inflation. The second objection is that the original-cost principle will be publicly rejected whenever, for reasons of price deflation or of technological progress, its maintenance calls for the establishment of rates of charge for service higher than current replacement costs. These two objections are obviously related; but we may treat them separately, the second in the paragraphs immediately following.

This objection runs to the effect that original-cost rate making is a deviation from competitive-price determination popular with the consuming public only as long as the deviation is in their favor. But let reproduction-cost appraisals fall in the future as they fell (or would have fallen had they come into widespread use) during the period of falling prices from the 1870s to the 1890s, and the very persons who now so loudly proclaim the fairness and efficiency of the actual-cost tests will shift their position and join in a demand that public utility rates be set free from the bondage of inflated historical costs.[18] Those rare stalwarts who demand consistency even of themselves will be hopelessly outnumbered by newer experts, by more recently appointed commissioners, and by other persons not bound by embarrassing prior commitments.

More serious, perhaps, than the danger of an official reversion from a well-established actual-cost rate base to a lower, fair-value rate base would be the danger of competition from new, publicly owned utility systems, possessed of plant and equipment both more efficient to operate and less costly to construct. To persons who feel sure that this country will never again undergo a major decline in price levels, this danger may not seem serious. But there remains the danger that full recovery of the costs of old plant and equipment may be precluded by revolutionary developments in the technique of production, for example, in the field of atomic energy. The actual experience of the railroads, and the even sadder experience of the electric street railways, are examples of such a danger.

[18] Writers on the history of rate regulation have often noted that, when the upward trend in prices tended to make "fair values" higher than reported original costs—a tendency that became marked by the time of the First World War—various spokesmen for consumer interests and for company or investor interests shifted sides so as to maintain the more "practical" type of consistency—support for the lower or the higher rate base, respectively. When railroad rates in Nebraska were at issue in the litigation leading to the Supreme Court's pronouncement in Smyth v. Ames, 169 U.S. 466 (1898), Mr. William Jennings Bryan, as counsel for the state, argued that, if the constitutionality of the rate statutes was to be tested by reference to any fair-return standard, this return should be related to current reproduction costs and not to the much higher corporate book values. These latter values, however, were said to have been grossly inflated through the practice of stock watering.

A completely reassuring answer to this objection is not possible in my opinion. Hence, one must put down to the debit of an actual-cost standard the distinct possibility that it may later become inoperative. For at least two reasons, however, I do not find these objections sufficient to condemn the standard. In the first place, even when the fair-value principle is in force, as it now is in Ohio and some other states, it may well later be renounced as unworkable or as contrary to the public interest. In the second place, the danger that an actual-cost rate base may be difficult to sustain in the face of falling prices or of technological progress, can be reduced, even though not avoided, by rapid cost-recoupment in the form of liberal allowances for depreciation. As to any danger that may still remain, it can be and should be allowed for in the concession to public utility companies of "fair rates of return" well in excess of interest on secure loans. More will be said on this point in Chapter XIV, which will stress the fact, well illustrated in the transportation field, that not even a reproduction-cost or "fair-value" principle of rate making can survive more than a limited degree of extraordinary technological obsolescence.

FAILURE OF AN UNMODIFIED ACTUAL-COST STANDARD TO SAFEGUARD STOCKHOLDERS AGAINST PRICE INFLATION

For reasons already suggested in this chapter, and for other reasons to be discussed in Chapter XIV, the "practical" advantages of an actual-cost standard of rate making are so great, and the "theoretical" advantages of a reproduction-cost standard are so dubious, that many writers predicted a general shift from the latter standard to the former following the renunciation of the "fair-value" doctrine by the Supreme Court as a mandatory "law of the land." Up to a point, history down to date has confirmed this prediction; for the majority of states, including some that have adhered verbally to a "fair-value" rule of rate making, have actually applied some version of an original-cost rate base with little or no recognition of current reproduction costs.[19]

Even today, however, the so-called "fair-value" rule of rate making has not yet suffered its oft-anticipated complete demise. Indeed, in several jurisdictions it has been restored to some measure of its earlier vigor by the action of a commission, a court, or a legislature. But one would be naive in assuming that the partial restoration has been based on any conversion of influential political interests to a reproduction-cost or present-value theory of rate making as distinct from an actual-cost theory. Almost certainly, the revival of the fair-value doctrine has been based on another consideration: namely, on the failure of the actual-cost standard, in its traditional version, to make any direct allowance for the serious, continuing price inflation. Rightly or wrongly, many fair-minded people have regarded this failure as grossly unfair to public utility stockholders, on the ground that it measures the stockholder investment in terms of dollars that have lost their former significance.

[19] Attempted classifications of the state and Federal jurisdictions by reference to the accepted measure of the rate base are unsatisfactory because of the prevalence of compromise measures, because not all commissions have adhered to uniform practice, and because commissions, courts, and legislatures have played fast and loose with the terms "value" or "fair value" as standards of rate control. For a partial classification, see a published report by the Federal Power Commission, *State Commission Jurisdiction and Regulation of Electric and Gas Utilities*, June, 1954. A more recent study of rate cases prepared by the public accounting firm of Arthur Andersen & Co. finds that the commissions in 21 states and in the District of Columbia, together with the Federal Power Commission, "have explicitly adopted original cost or investment as the rate base"; that the commissions of 7 states, while subject to statutes imposing fair-value requirements, have actually given "sole or predominant weight to original-cost evidence"; and that in 12 states "fair value as defined in *Smyth* v. *Ames* is still the test of a lawful rate base . . . although for various reasons original cost or investment has been adopted in a number of decisions." *Return Allowed in Public Utility Rate Cases*, Supplement #3 (1959).

In New York State, because of an utterly irrational distinction in the statutory provisions as to the criteria of reasonable rates, gas and electric companies are subject to an actual-cost standard, whereas telephone and transportation companies are subject to a standard which must give an unstated degree of consideration to an undefined value of the property—a "value" presumably somehow derived from estimates of reproduction cost. New York Telephone Co. v. Public Service Commission, 309 N.Y. 569 (1956). In 1957, the Maine legislature, following a court decision imposing a fair-value test, passed a bill providing that the commission, in fixing a rate base, "shall not include current value." On the other hand, the Minnesota legislature passed a law making it mandatory for the commission (which lacks control over gas and electric companies) to take "fair value" into account.

Adoption of a fair-value measure of the rate base has been seen as the most expedient way by which to make amends for this failure. For this purpose "fair value" is not identified with a reproduction-cost rate base, since such a rate base would often confer upon the common stockholders enhancements in the dollar values of their equity securities far in excess of any increases in general price levels or in current "costs of living." But, in line with traditions followed at times (though rejected at other times) by the Supreme Court, "fair value" has been interpreted to mean a rate base which, while derived in large measure from actual costs, gives some "equitable consideration" to estimates of depreciated replacement cost. And in this way, what goes under the name of the "fair-value" rule can really be turned into a liberalized version of the actual-cost rule, the liberalization taking the form of some equitable upward adjustment in the rate base as an offset to price inflation.

The question whether or not any such offset is justified, either in fairness to corporate stockholders or as a necessary concession to the need to attract equity capital, presents an extremely complex problem. Its discussion will be deferred to Chapter XV, on "The Fair Rate of Return," since any desired adjustment for inflation can be made through the percentage rate rather than through enhancements of the rate base. But what should be noted here is that, if such adjustments are to be applied to the rate base, they can be made more effectively through price-index revisions of an actual-cost rate base than through engineering revaluations of the public utility properties. Indeed, resort to reproduction-cost appraisals is an absurdly crude device by which to protect public utility stockholders against the impairment of their capital investment or of their "real income" against price inflation: first, because the appraisals apply to the entire corporate property rather than to the common-equity interest therein; secondly, because the price changes that they record are changes in construction costs, not changes in cost-of-living indices; and thirdly, because their allowances for depreciation are not related directly to the actual depreciation reserves. The import of this last statement will be noted in the following chapter.

XIII

THE RATE BASE: ALLOWANCES FOR DEPRECIATION UNDER AN ACTUAL-COST STANDARD

In an effort to explain, free from confusing complications, the general nature and claimed advantages of an actual-cost or net-investment principle of reasonable rates, the last chapter has paid only casual attention to the most difficult problem of measurement—that of proper allowances for depreciation. We must now discuss this problem before turning, in the next chapter, to the reproduction-cost or present-value theory of rate regulation. But in order to simplify a discussion that must remain somewhat complex in any event, we shall assume in this chapter the existence of stable price levels, with a mere footnote reference to the important question whether, in periods of general price inflation or deflation, offsetting adjustments should be made in the allowances for accruing and accrued depreciation.[1] Such adjustments would be re-

quired under that modified version of an actual-cost rate base, noted at the end of the last chapter, which restates historical costs in dollars of equivalent purchasing power. But in other respects, the relevant concepts and procedure of depreciation accounting would be the same as those to be discussed here, contrary to the requirements of a strictly construed reproduction-cost or present-value standard of rate making.[2]

For convenience in exposition, this chapter is divided into three main sections. The first section discusses the meaning of "depreciation" as the negative term of the rate base—as the amount to be deducted from actual or original cost new in arriving at the depreciated cost or net investment on which a public utility com-

[1] See p. 275, *infra*. For a discussion of price-level adjustments in business-income determination, see Study Group on Business Income, report entitled *Changing Concepts of Business Income* (New York, 1952); James L. Dohr, "The Next Step in Depreciation Accounting," 89 *Journal of Accountancy* 114–119 (1950); the same author's "Limitations on the Usefulness of Price Level Adjustments," 30 *Accounting Review* 198–205 (1955); F. Warren Brooks, "Needed Reform for Utility Tax Depreciation," *Public Utilities Fortnightly*, Sept. 24, 1953, pp. 3–11. But in public utility rate making under the general philosophy of an actual-cost standard, there arises the need to avoid the introduction of price-level adjustments that would make the common stockholders the recipients of capital gains and losses resulting from the inflexibility of interest and preferred-dividend requirements. I believe that the most promising solution of this problem would lie in the application of the price-index adjustments to the entire plant of a public utility company (and not merely to the common-stock equity in this plant), combined, however, with the creation of a consumer-equity account to which would be credited all dollar write-ups in excess of those needed to restate the common-stock capital in dollars of current purchasing power. A corresponding split-up of the depreciation reserve would also be required.

[2] But in "fair-value" jurisdictions, courts and commissions play fast and loose with the value concept, with the result that their treatment of depreciation is often impossible to reconcile with any basic "theory" of reasonable public utility rates. In a letter to me commenting on this situation, one of the country's leading rate experts, with a wide experience as a witness in different jurisdictions, writes: "The subject is handled so loosely, erratically, and variously by different regulatory bodies that a general philosophical discussion of depreciation would have little practical importance." Appraisers, he adds, sometimes start with a cost-new figure above original costs (either estimated reproduction costs or book costs adjusted by price indices) and apply to this basic cost a deduction for depreciation equal to the depreciation reserve enhanced by the per cent by which the basic cost exceeds the book cost.

In so-called "fair-value" states, the most obvious departure from any practice consistent with a present-value or reproduction-cost rate base has lain in the almost uniform acceptance of book costs, unenhanced by price indices, as the basis on which to calculate the annual allowance for depreciation as an operating deduction. See National Association of Railroad and Utilities Commissioners, Report of Committee on Rates of Public Utilities, *1954 Proceedings*, pp. 197–199, noting the general refusal of commissions to allow what has been called "economic depreciation." See also the separately printed 1954 Report of the Association's Committee on Depreciation which, in rejecting the "economic-depreciation" argument, notes that a public utility official, in advancing it, had admitted that, in the event of a decline in prices, his position would need to be "reconsidered." 53 *Public Utilities Fortnightly* 556–557 (April 29, 1954).

More recently, the public utility trade journals have hopefully reported a few rate cases which concede a company's claim for annual depreciation allowances based on higher costs than book costs. See Re Indiana Telephone Co., 16 PUR 3d 490 (1957); Iowa-Illinois Gas and Electric Co. v. City of Fort Dodge, 248 Iowa 1201, 20 PUR 3d 159, 85 N.W. 2d 28 (1957); Texas Railroad Commission v. Houston Natural Gas Corp., 155 Texas 502, 13 PUR 3d 90, 289 S.W. 2d 559 (1956).

In earlier days, while still adhering to the "fair-value" doctrine in *Smyth v. Ames*, the Supreme Court held that a public utility is entitled to a depreciation basis measured by the current value of its property rather than by its original cost. United Railways Co. v. West, 280 U.S. 234, 252–254 (1930). But when it renounced the value doctrine in the *Hope Natural Gas* case, it expressly overruled its previous ruling on depreciation. 320 U.S. 591, 606–607 (1944).

pany is entitled to an opportunity to earn a "fair rate of return." The second section discusses the annual allowance for accruing depreciation as an operating expense or operating deduction. The third section returns to the rate base in order to note exceptions to the general principle set forth in the first section—the principle which identifies "accrued depreciation" with recouped capital outlays. A more logical procedure would be to discuss first the depreciation allowance as an item of operating expense, since the concession of this allowance to the company is what justifies the deduction of accrued depreciation in the determination of the rate base. But I have chosen the present sequence in order to start with the question raised first in the actual controversies about a proper rate base.

MEANING OF DEPRECIATION AS A NEGATIVE TERM OF THE RATE BASE

Except for a company operating with brand new plant and equipment, the actual or original cost of the public utility properties does not constitute the usual measure of the rate base under an "actual-cost" standard. Instead, the accepted measure (with allowances for working capital and for interest during construction) is "cost minus depreciation." An applicable definition of depreciation is therefore called for.

Applied to property, depreciation is generally defined as decline in, or loss of, value; and this definition was formerly accepted by some accounting authorities as relevant to fixed-asset valuations in financial statements, although with the qualification that the term should refer only to those diminutions in value attributable to causes eventually leading to complete retirement—notably, wear and tear, action of the elements, obsolescence, and inadequacy.[3] Appraisal engineers have sometimes quoted the same or similar definitions as if they were also applicable to valuations based on estimated replacement costs. But in actual practice they have often used the term in another sense, as referring to a value differential rather than to a loss in value over any given period of time —to the difference between the lower value of the old and obsolescent existing property, and the higher cost (and hence, the higher assumed value) of a hypothetical new property.[4]

Both of these related conceptions of depreciation in terms of a value decrement or value deficiency would have their place in the determination of a rate base designed to reflect the present value of public utility properties as distinct from their cost. If this value were to be derived from a record of actual construction cost, the allowance for "depreciation" should reflect any fall in value, not otherwise recognized, that may have taken place since the date of the construction. If, as is more plausible for older properties, the value were to be deduced from an estimate of current replacement cost—and the relevant replacement cost, despite some judicial opinions to the contrary, is the cost of a modern substitute plant —the deduction for "depreciation" should summarize the value inferiority of the existing property, including the inferiority due to liability to earlier retirement. This deduction, moreover, should be subject to a partial offset for any superior quality of the present plant over the hypothetical modern substitute—a superiority often claimed in the early railroad valuations, in the form of allowances for roadbed solidification.

But when we turn to an actual-cost standard of rate control, there arises a serious problem of redefinition. For under this latter standard, actual cost is accepted as a measure of the rate base on its own merits instead of being accepted only in proof of the "real value" of the property. What, then, is the relevance of a negative term in the rate base, called "depreciation," which is so generally treated as a value concept?

Earlier writers sometimes answered this question by borrowing for rate-making purposes an accounting definition once suggested by a British authority, P. D. Leake.[5] Leake defined depreciation as "expired capital outlay"—in other words, as "expired cost"—thereby transferring the word from a value to a cost category. But this definition was a dodge rather than a solution, and the fact that

[3] See the several definitions quoted by the Committee on Terminology of the American Institute of Accountants in a report discussed below, pp. 201–202. The committee noted the lack of uniformity as to what value-reducing forces should be recognized in depreciation accounting.

[4] This distinction is discussed in my *Valuation of Property* (New York, 1937), Chap. 10. Its importance has been stressed by Professors E. L. Grant and Paul T. Norton, Jr., in their treatise *Depreciation* (New York, 1949).

[5] *Depreciation and Wasting Assets*, 3d ed. (London, 1920). The Interstate Commerce Commission once defined depreciation as "lessening in cost value." Valuation Docket No. 2, Texas Midland Railroad, 75 I.C.C. 1 at 125 (1918). But "cost value" is self-contradictory, as would be "weight-height," or "length-width."

it still enjoys some currency among accounting writers who must be aware of its spurious character illustrates the tenacity of convenient though specious phrases. For cost does not "expire." What may be said gradually to expire is the economic significance of the asset as it grows older, in short, its utility or its value. "Expired cost" is therefore mumbo jumbo, and a reversion to the old association of depreciation with loss in value would be a far more sensible alternative.[6]

Partly in view of the above-noted difficulties of reconciling the deduction for depreciation with the acceptance of a nonvalue rate base, some writers of earlier days denied the propriety of any deduction.[7] Original cost, they declared, is original cost—a purely historical datum; and it should not be discounted for depreciation unless the resulting rate base purports to reflect what the properties are now "really worth," contrary to the philosophy of a cost basis of rate control.

Fortunately for the financial soundness of the public utility companies as well as for the efficiency of rate regulation in other respects, this view no longer prevails. Under a properly administered actual-cost or net-investment standard of rate control, the necessity of making allowances for accruing and accrued depreciation as operating charges and as rate-base deductions, respectively, is now generally conceded. No doubt the income-tax laws, which

[6] The current uniform systems of accounts prescribed for public utility enterprises by the state and Federal commissions incorporate, with minor variations, a definition proposed in the 1938 Report of the Special Committee on Depreciation of the National Association of Railroad and Utilities Commissioners: ". . . the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance." "Service value" is in turn defined as "the difference between the original cost and the net salvage value of the utility plants. . . ." Taken literally, this last-quoted statement would identify "service value" with cost and hence would not make sense. I assume, however, that the statement was intended merely to designate the quantum of property to be affected by the depreciation account.

[7] See my *Valuation of Property* (New York, 1937), Chap. 31, revising a view that I had previously taken in 27 *Columbia Law Review* 113–131 (1927). Some of these early writers denied the very existence of depreciation as applied to a large, well-maintained plant composed of a great number of assets due for retirement at various times. A brief critique of this plant-immortality doctrine appears on pp. 207–209 and 1127–1129 of the book just cited; but the more recent literature appears to deem the doctrine unworthy even of discussion. The combined forces of income taxation and of rapid technological progress have made it clearly indefensible.

have given public utility companies an incentive to take for tax purposes deductions as liberal as the Internal Revenue Service will permit, have done much to change current attitudes, even on the part of the corporate managements.[8]

As yet, the problem of rationalizing the modern practice of depreciation accounting by means of formal definitions that will aid in the further development and improvement of the practice itself has not received a completely satisfying solution. But a promising approach to such a solution has already won widespread acceptance, namely, in the identification of "accrued depreciation" with an amortized cost only indirectly related to decline in value. The significance of this nonvalue definition will now be noted.

ACCRUED DEPRECIATION DEFINED AS AMORTIZED COST AND NOT AS DECLINE IN VALUE

Under an actual-cost philosophy as I construe it, the deduction for depreciation as a negative term of the rate base does not purport to measure the loss in value actually sustained by the depreciable fixed assets since their dates of acquisition. What it represents is the amortized costs of the assets in the sense of that part of the costs which has already been charged, or which should have been charged, to previous periods of operation. "Cost minus depreciation" is therefore a shorthand expression for costs remaining to be amortized by future charges to operation and hence indirectly by future charges against the consumers of public utility service.

This denial that depreciation here means fall in value is not tantamount to a denial of any important relationship between the two concepts. As a matter of sound accounting and sound price fixing, the rates at which capital costs are gradually transformed into a series of charges to operating expense should be based on plausible assumptions as to downward trends in asset values in the course of their useful service lives. More will be said on this point in

[8] Rules of depreciation accounting accepted in income-tax administration are not binding, as a general rule, on companies in the publication of their annual reports or on commissions in their calculations of revenue requirements for rate-making purposes. But the presence of wide and chronic differences is a source of justifiable suspicion that either the one rule or the other may be invalid. This suspicion, in my opinion, justly applies to the distinction currently drawn between the diminishing-charge methods of cost amortization permitted under Section 167 of the 1954 Internal Revenue Code and the less rapid methods of depreciation still adhered to for purposes of public utility accounting and rate control. See pp. 218–222, *infra*.

the second section of this chapter. But even so, what is deducted *sub nomine* "depreciation" is the cost that has been, or should have been, amortized and not the actual decline in value, estimated with benefit of hindsight.

Under a systematic and consistently applied program of rate regulation, this procedure of capital-cost amortization through annual charges to revenue account is by no means one of mere bookkeeping. Instead, it is designed to afford a company an adequate opportunity to recoup from consumers its investments in fixed assets during their estimated useful-service lives. The deduction for depreciation makes the rate base portray the company's net investment in used and useful properties—that part of its gross investment which it is entitled to recoup in the future and on which it is meanwhile entitled to earn a "fair rate" of return.

Were it not for qualifications to be discussed in the third section of this chapter, one might therefore correctly substitute "recouped investment" for "accrued depreciation" as the thing to be deducted from cost new in the measurement of the rate base. Temporarily, these qualifications will be ignored for the sake of simple exposition. Hence, in this section and in the second section, we shall assume that the deduction for depreciation is to be measured by the company's existing depreciation reserve, and that this reserve reflects whatever portions of the cost of existing plant and equipment have already been recovered by the company through charges for service imposed on previous customers.

Not all company spokesmen have conceded the validity of the above-stated rationale of a deduction for depreciation in the measurement of the rate base.[9] Some of them have insisted that any re-

[9] Even today, some public utility representatives oppose revisions in the uniform systems of public utility accounts requiring the showing of depreciation reserves, not on the liabilities side of the balance sheet but as a contra to property on the assets side—a showing that has the support of modern accounting authorities. See William A. Paton and William A. Paton, Jr., *Asset Accounting* (New York, 1952), p. 399. The revision is opposed as lending credence to the deductibility of the reserve for rate-making purposes.

A compromise between the deduction and the nondeduction of the depreciation reserve once gained some favor. Here, the rate base is set at undepreciated cost; but, in the determination of the annual revenue requirements for rate-making purposes, the consumers are credited with a notional rate of interest (typically 3 per cent) on the amount of the depreciation reserve. That part of the gross costs of the properties reflected by the reserve is thus treated as if it had been financed by a consumer loan, instead of being treated as a cost already recouped from the customers. This procedure may still be followed in a few states. But its days are numbered since it rests on arguments of such a flimsy nature.

coupment of investment made possible by the allowance for accruing depreciation as an operating charge is a mere recoupment by the corporation and not by its security holders. This contention is quite true in the normal situation of continuous plant expansion, since the revenues that cover the depreciation charges are regularly reinvested in new plant and equipment instead of being paid back to stockholders or bondholders. But when the reinvestment takes place, the cost of the new property, whether in the nature of a replacement or of an improvement, is charged to plant account and added to the rate base. No net reduction in the rate base takes place.

What has just been said would need modification if a company should find it necessary to set aside all or part of its depreciation-covering revenues in a special replacement-reserve *fund* made up of cash or of highly liquid securities yielding low rates of interest. But reserve funds of this nature are seldom required in public utility finance and, if required, are properly treated as creating special situations. A more important qualification is that called for when a company cannot time its replacement and expansion program so as to reinvest its retained revenues without material delay. As a result, the company may be in temporary possession of redundant liquid assets which it must hold until needed. Here again, some readjustment is called for in fairness to the corporate investors. But the readjustment does not require the nondeduction of the full depreciation reserve. Instead, it can take the form of an allowance in the rate base for "construction working capital" over and above the conventional allowance for operating working capital.

THE ALLOWANCE FOR DEPRECIATION AS AN OPERATING EXPENSE

Our provisional identification of accrued depreciation with recouped capital outlays supplies a partial answer to the basic question raised near the beginning of this chapter—that of the relevance of a deduction for "depreciation" in the measurement of an actual-cost rate base. But it leaves unsolved another problem in depreciation accounting for rate-making purposes: the determination of a proper annual allowance for accruing depreciation as an operating expense. This problem is still highly controversial and will doubtless long remain so because of the absence of any single, "theoretically correct" solution and because the choice of a wise, workable solution must be based on a variety of partly conflicting considerations, the quantitative importance of which defies precise measurement.

In one respect, however, the actual-cost principle greatly simplifies the task of securing a workable solution. For, properly administered, it minimizes the issue of fairness to investors because it permits a marked degree of coordination between the allowances for *current* depreciation as an operating deduction and the build-up of the reserve for *accrued* depreciation. With one important qualification and with appropriate adjustments in the "fair rate of return," *any* method of amortization (say, group straight-line) can be made as fair to investors as any other (say, sinking fund). The important qualification is that the method which contemplates the faster recoupment is likely to be the one offering the greater assurance that the recoupment will actually take place. More will be said on this point in a later paragraph.

THE DEPRECIATION ALLOWANCE VIEWED AS A TEMPORAL COST APPORTIONMENT

On the general character and significance of the annual allowance for accruing depreciation, as distinct from its measurement, there is no longer room for serious dispute in the light of modern accounting theory. The allowance for any given year is but one step in a systematic and gradual transfer of capital costs into a series of charges to current operations during the estimated useful lives of the depreciable fixed assets. In this way, the attempt is made to apportion the costs of the assets among the years during which they perform service instead of charging them in lumps either to the year of acquisition or to the year of retirement. Thus the cost of a depreciable fixed asset is treated as a prepaid expense, to be amortized through a series of subsequent charges against current revenues.

This conception of the nature of depreciation allowances for rate-making purposes coincides with the modern view of depreciation accounting as a tool of business-income determination.[10] In

[10] More than twenty years ago, this position was taken by Professor Perry Mason, in his *Principles of Public-Utility Depreciation* (Chicago, 1937).

a much-quoted report on the latter subject, the Committee on Terminology of the American Institute of Accounting expressed this view as follows:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.[11]

The view, accepted by the Committee on Terminology with respect to financial statements and accepted in this book with respect to rate regulation, that depreciation accounting is a form of cost apportionment and *not* a process of annual reappraisal, offers a useful approach to the problem under review.[12] The further requirement that the method of amortization must be systematic rather than haphazard or rather than subject to the convenience of the management, while not wholly free from ambiguity, offers one step toward a solution by its exclusion of a number of inadvisable ways of accounting for retirements or replacements that were once practiced by public utility companies. But while retirement accounting and replacement accounting would be ruled out, there would still remain room for choice among a rich variety of alternatives, each expressible by curves of mathematical simplicity or elegance.

As to the basis of choice among these alternatives, the Com-

[11] American Institute of Accountants, *Accounting Research Bulletin*, No. 22 (New York, 1944), reprinted in the Institute's *Accounting Terminology Bulletin*, No. 1 (New York, 1953). In an illuminating article on "Concepts of Depreciation," Louis Goldberg of the University of Melbourne compares this conception of depreciation with that previously expressed by the Institute of Chartered Accountants in England and Wales. 30 *The Accounting Review* 468–484 (1955).

[12] But in one important respect the report of the Committee on Terminology seems to me subject to serious criticism: namely, in its failure to note that the distinction between a cost allocation and a valuation is not that of an antithesis. Perhaps the Committee took this point for granted. But I have seen the report cited as authority for the statement that, *since* depreciation accounting is a procedure of cost allocation, it *therefore* cannot be designed to reflect the decline in asset values between dates of acquisition and dates of retirement. Such a conclusion is a *non sequitur*. Conceivably, the cost allocation itself may be based on plausible assumptions as to rates of asset-value deterioration.

mittee on Terminology was content to declare that the method of allocation, in addition to being systematic, must also be "rational." But it did not supply any criteria of rationality, although it wisely implied that any of various alternatives might be rational—possibly *equally* rational in the dim light of foreknowledge of future events and probable consequences. Other writers have discussed at length criteria of rationality or reasonableness, either with respect to standard financial accounting or with respect to rate regulation.[13] But the subject is highly involved, and what follows is designed chiefly to illustrate the difficulty of the problem and the need for further analysis in the light of actual experience.

THE APPORTIONMENT OF COSTS ON RELATIVE-BENEFIT PRINCIPLES

Applied under an actual-cost philosophy of rate control, the rationale of the systematic transfer of capital costs originally charged to plant account into a series of smaller charges to operating costs is a corollary of the principle that the costs of supplying public utility services should be borne, as far as feasible, by those customers who derive a benefit from the particular outlays in question. It is for this reason that the burden of reimbursing a company for the acquisition of capital assets is distributed over the periods during which customers will enjoy the use of these

[13] In its application to accounting for unregulated industries, the subject is discussed by all the advanced treatises on accounting. See also E. L. Grant and Paul T. Norton, Jr., *Depreciation* (New York, 1949). These authors, rightly in my opinion, insist on the indeterminate character of depreciation accounting: pp. 39–40, 184, 365.

In rate regulation, the law and practice of depreciation accounting are discussed by the textbooks on public utility economics or rate making. The lead in the modern development was taken by the New York and Wisconsin commissions during the 1930s, following two famous Interstate Commerce Commission Reports, *Depreciation Charges of Telephone Companies* (No. 14700) and *Depreciation Charges of Steam Railroad Companies* (No. 15100), written by Commissioner Eastman, 118 I.C.C. 295–411 (1926). A report on *Depreciation—a Review of Legal and Accounting Problems*, by the staff of the Wisconsin Public Service Commission (Madison, 1933) was followed, in 1943, by a more elaborate *Report of Committee on Depreciation* of the National Association of Railroad and Utilities Commissioners (Washington, D.C., 1943). This notable document appeared several years after some state and Federal commissions had made depreciation accounting mandatory under the uniform systems of accounts, thereby making obsolete the retirement-expense accounting hitherto so widely practiced by the nontelephone utilities with commission sanction. 1936 is often cited as the year of the general change-over to depreciation accounting.

assets. By the time when the assets have ceased to perform a useful service, their costs should already have been fully recovered.[14]

Since a "benefit rationale" is basic to the whole process of depreciation accounting, viewed as an instrument of rate regulation, one naturally looks to the same rationale for guidance as to a choice of a reasonable method or rate of cost amortization. Equal apportionments, one may assume, should be made to years of equal benefit; heavier apportionments to years of heavier benefit. Or rather, the amortization of the costs should take place at such a rate that, in combination with the allowed fair rate of return on those capital costs that are still unamortized, plus the annual allowances for taxes imputable to those assets, it will impose annual burdens on consumers related as closely as feasible to the relative benefits conferred upon them by different years of use. In the determination of these relative benefits, account must be taken of the fact that the use of newer and more modern fixed assets will free consumers from the obligation to defray the heavier current operating expenses imposed by the retention of aged and obsolescent assets—expenses exclusive of depreciation allowances but inclusive of all charges for current maintenance.

This relative-benefit criterion of a sound basis of depreciation accounting for rate-making purposes presents serious conceptual difficulties quite aside from the obvious practical problems of *ex ante* measurement—difficulties that have not often been squarely faced in the literature. Indeed, the difficulties are probably insoluble without resort to convenient fictions or hypotheses, the validity of which must rest on their workability for practical purposes of rate control. One way to envisage the problem is to view it as a search for rates of cost amortization that, together with the allowances for a fair return and for taxes, will be roughly correlated with the annual rent values of plant and equipment—rent values which, in all probability, will gradually decline as the property grows older, contrary to the behavior of Oliver Wendell Holmes's "one-hoss shay."

[14] As Dr. Terborgh points out, the replacement of assets is likely to take place continuously, or in a series of steps, *antedating* the retirement of the assets. This gradual process of "degradation" is characteristic of electric generators, which are used less and less as they grow older, finally being relegated to the status of stand-by equipment. See George Terborgh, *The Bogey of Economic Maturity* (Chicago, 1945), pp. 102–108.

But at best, since the cost apportionments must be made *ex ante,* subject only to a minimum of midstream revisions, any correlation between the resulting annual charges imposed on consumers for capital costs (depreciation plus fair return plus taxes) and the relative benefits derived by consumers from the use of older assets as compared to newer assets, must be extremely rough. Hence, the choice of any given method of depreciation accounting must not be premised on any assumption of a close adherence to a relative-benefit standard.[15]

An alternative rationale of the periodic assignment of depreciation charges may be preferred to the one just suggested. But it amounts to a restatement of the same idea in a different form. Here, the annual allowance for depreciation is an allowance for an assumed, probable rate of decline in the service values of the assets—a decline typical of assets of the character and ages of the assets in question. Being systematic and standardized, this allowance cannot portray the many ups and downs in asset values between dates of birth and dates of death. It therefore represents, not the actual changes in value from year to year but a stylized allowance for a downward trend. But with all of its practical and conceptual deficiencies,[16] this indirect association between annual

[15] The absence of any such close association is implicitly recognized by the acceptance of rules of rate regulation that do not require an increase or decrease in rate levels, year by year, designed to maintain a constant or completely stable rate of return for each year. While the revenues of any one year will *usually* suffice to cover all operating deductions including the current allowance for depreciation, and while the instability of these revenues is therefore usually reflected only in the realized rate of return, or only in the reported net income, the apparent uniformity with which the consumers of a given year pay for the depreciation allowance of the same year is merely a uniformity of an accounting convention—a convention which alone determines what part of revenues shall be deemed to constitute a recoupment *of* capital as distinct from that part which shall be deemed to constitute a return *on* capital. See p. 363, *infra.*

[16] The major theoretical difficulty is that of securing an acceptable definition of "service value" applicable to a regulated utility. "Market value" is clearly disqualified except, arguably, for those very limited classes of public utility assets (such as trucks or office buildings) that continue to enjoy a significant sale value even after their acquisition by the operating company. If the company were free from rate regulation, the value of the asset to its present owner (sometimes called "value to the going concern") would be the relevant value. But, within limits, the value of an asset to a public utility company is whatever value a commission is willing to give it for rate-making purposes! Hence, as suggested in Chap. XI, some conception of value to the consuming public, or of value to a hypothetical company, is required.

Despite conceptual difficulties, a value concept of the type just suggested is not merely useful but utterly indispensable for the rational management of public

charges for accruing depreciation and annual decrements in asset values seems to me to come closer to supplying a plausible "theory of depreciation accounting" than has any suggested alternative.

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SINKING-FUND, STRAIGHT-LINE, AND DIMINISHING-CHARGE APPORTIONMENTS

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A systematic treatment of the subject of this chapter would now call for a review of alternative methods of depreciation accounting, including group methods as well as unit or item methods, by reference to the somewhat vague criterion of "rationality" suggested in the preceding paragraphs. Such a treatment, however, would go far beyond the scope of this book. The reader is therefore referred to the special treatises on depreciation for an exposition and critical appraisal of the different alternatives. ~~But~~ A brief comment is ~~here~~ in order ~~as to the bearing of the preceding discussion~~ on the relative merits of three different methods of systematic cost amortization referred to as straight-line apportionment, interest procedure, and decreasing-charge methods.[17] ~~The~~ straight-line Method, which is the one now most generally applied by public utilities, amortizes the costs of assets (minus net salvage) through equal annual charges over estimated service lives. Interest procedures, which include the sinking-fund method, begin with gentler charges, which are increased year after year as the asset approaches retirement. Decreasing-charge methods are illus-

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utility companies. Quite aside from any use to be made of it in systematic depreciation accounting, it is essential to rational decisions as to the timing of retirements and of replacements. A decision that an old or obsolescent asset ought now to be retired is tantamount to a conclusion that, in the light of its limited efficiency, its *present service value* is now less than its net-salvage value. And a rational decision to buy a new asset (whether in the nature of a replacement or of an addition) is tantamount to a conclusion that the asset will be *worth* at least its cost!

[17] William A. Paton and William A. Paton, Jr., *Asset Accounting,* p. 268. The authors add a fourth category: production and revenue methods, which relate the periodic charge for depreciation to rates of service output during each period (say, electric energy output in kilowatt-hours) or to operating revenues. While these two related methods are subject to theoretical objections, their chief limitations lie in the practical difficulties of making them keep step with the principle of (complete) cost amortization during the useful service lives of the fixed assets. See the above-noted (footnote 13) *Report of Committee on Depreciation,* pp. 62–64, 71–77. Despite these difficulties, further study of their possible application in public utility accounting and rate making, perhaps in combination with the more orthodox straight-line accounting, is warranted with special reference to the phenomenon of the business cycle. The study should consider the actual experience of the Canadian Pacific Railway in part-way application.

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trated by the declining-balance method and the sum-of-the-years-digits method, both of which now enjoy limited acceptance under the current income-tax laws. They impose larger annual write-offs in earlier years than in later years, whereas the interest-procedure methods impose smaller write-offs in the early years.

The sinking-fund method, and not the straight-line method, is the one which, except for taxes, tends to impose upon consumers equal annual capital charges for the use of a fixed asset. For under this method, when applied to rate regulation, the sum of the charge for return *of* capital (the annual depreciation charge) and the charge for the return *on* capital (the "fair rate of return") tends to remain the same during the life of the asset.[18] While the sinking-fund method formerly enjoyed some favor among commissions, it now has but little standing in comparison with the somewhat simpler and more conservative straight-line apportionments.

Although a straight-line method is designed to impose equal annual depreciation charges during the lives of the assets, it actually makes some allowance for declining annual rent values when used in conjunction with a rate base measured by depreciated cost. For, under this combination, the sum of the diminishing fair return plus the constant depreciation charge grows smaller and smaller as the assets approach retirement. Thus, the failure of straight-line expressly to recognize the ~~interest or~~ time-discount factor in the decline of capital values over periods of time serves as an offset, in the nature of a countervailing fiction, to its apparent assumption that fixed assets will have undiminished annual rent values throughout their service lives.[19] But any precise offset

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[18] This statement assumes that the sinking-fund accumulations are based on a rate of interest equal to that of the allowed rate of return. But it ignores the income-tax factor as an additional capital charge, a serious omission in these days of high income-tax rates. ~~On this point Mr. Gordon R. Corey, Financial Vice President~~ of the Commonwealth Edison Company, writes me ~~as follows~~: "Federal income taxes ~~often~~ have strange effects upon carrying ~~charges~~. For example, the level-premium annual ~~carrying~~ charges on an investment in property with a 35-year life, which can be depreciated on a ~~declining~~ balance basis for Federal income tax purposes, are approximately 9½%, while ~~such~~ annual carrying charges on an investment in perpetuity, which cannot be so ~~depreciated~~, are about 1½% higher or 11%. This comparison assumes a 6¼% return, a 52% income-tax rate, and 52% debt with a 3½% interest rate on the debt."

[19] The significance of the failure of straight-line to recognize the ~~interest or~~ time-discount factor in asset valuation is illustrated by the valuation of property assumed to have a constant annual rent value, as typified by an annuity certain. Consider, e.g., the valuation of a twenty-year, $1,000 annuity, valued on the basis of a 5 per cent interest rate compounded annually. When first purchased, one year

would be purely coincidental, since there is no reason to infer a causal or statistical relationship between the phenomenon of time discount and the phenomenon of deteriorating annual rent values.

Diminishing Charge Depreciation

At the present time, income-tax considerations are leading many public utilities to adopt some permitted version of diminishing-charge depreciation in their determination of taxable income. This practice will be discussed in ~~the third~~ another section of this chapter. But some authorities have insisted that, quite aside from tax aspects, straight-line depreciation accounting fails to give adequate recognition to the typically sharp downward trend in annual rent values during the earlier and rosier years of useful service life—a trend so marked that it is not adequately counterbalanced by the interest-factor offset noted above.[20] Applied to public utility rate control, this contention would imply that diminishing-charge methods of cost amortization should be accepted in the determination of the annual allowance for accruing depreciation and hence in the future build-up of the depreciation reserve. The validity of this contention cannot be proved or disproved by mere "depreciation theory"; [21] but it derives practical support from an argument, presently to be noted, in favor of rates of amortization which minimize the more serious danger of going too slow by running the less serious danger of going too fast.

before the first annuity payment, the annuity will be worth $12,462.21. In ten years, when half of its life has expired, the value will fall to $7,721.73, about 62 per cent of the initial value. Yet straight-line amortization would reduce the value by 50 per cent, to $6,231.10.

[20] This states the defense of diminishing-charge methods of depreciation accounting in its most plausible form. But the more frequent form of this defense completely ignores the fact that even straight-line methods give some recognition to declining-rent values through their countervailing failure to allow for the time-discount factor. The denial by some accounting authorities that this latter factor has any bearing on the proper allowance for fixed-asset depreciation, as an item of operating expense, may perhaps be explained by the refusal of standard ~~financial~~ accounting to recognize interest requirements as a production cost.

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[21] One of the country's distinguished authorities on depreciation draws the following conclusions from theoretical and empirical evidence: "(1) It seems quite clear that the straight-line writeoff is a gravely retarded method of depreciation for productive equipment. Any realistic allocation procedure should get rid of at least one half of the initial value over the first third of the service life and at least two-thirds over the first half. (2) The straight-line method is apparently less retarded for buildings and structures than for equipment, how much less it is impossible, on the basis of the available evidence, ~~to say~~." George Terborgh, *Realistic Depreciation Policy* (Chicago, 1954), p. 47. For an illuminating discussion of the most plausible assumptions as to the probable future rates of electric power plant depreciation, see Joseph Lerner, "Capital Costs of Private vs. Public Power for A.E.C.—a Review," 33 *Land Economics* 113–126 (1957).

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Other

~~"PRACTICAL"~~ CRITERIA OF COST APPORTIONMENT

Temporal Fairness to Customers.

~~Aware of the vague and unsatisfying~~ nature of any attempt to rationalize the choice of a method of depreciation accounting by reference to some basic "theory" of temporal cost apportionment, such as a relative-benefit theory, one may be tempted to conclude that, within wide limits, any method of amortization is as good as any other. This conclusion, however, does not follow. For the relative merits of alternative methods are subject to appraisal in the light of criteria of usefulness other than those suggested by any assumed ideal standard of fairness among the consumers of different periods. The importance properly attached to other criteria is all the greater in view of the fact that most public utility consumers are fairly steady customers and hence that *any* chosen method of cost amortization, consistently followed, will to a material degree offset in a later period of time deficiencies or excesses of an earlier period.

Conservatism of Finance

Aside from the marked advantages of methods of depreciation accounting that are relatively simple, understandable, and uniform throughout the country, one may properly give weight to the criterion of conservatism from the standpoint of corporation finance. This criterion suggests that, as between two proposed methods of cost amortization, one of which undertakes faster write-offs than the other during the early years of useful service lives, any reasonable doubt may well be resolved in favor of the former unless, in consequence, the resulting temporarily higher rate levels will be a serious deterrent to the development of a demand for utility services commensurate with plant capacity.[81] However, Acceptance by consumers of a slightly higher current rate level may be a price well worth paying for lower rate levels in the long run.

There are at least two reasons in support of this canon of conservatism. The first is the more obvious one that a public utility company may be better protected in its opportunity to enjoy a complete recoupment of its capital investments, combined with a fair rate of return on the unrecouped portions, if the attempted rate of recoupment is fairly rapid during the earlier years of the service lives of its assets. If recoupment is delayed until obsolescence has proceeded beyond a somewhat ill-defined limit, the traffic may no longer bear, nor public opinion tolerate, rates of charge for service high enough to continue the procedure thereafter. The experience of the railroads and of the street railways strikingly illustrates this danger.

The second reason in favor of liberal depreciation allowances during early years of service life concerns the effect of the allowances on the replacement policies of the management. As guardians of the investor interests, a management will naturally be reluctant to replace obsolete equipment with new equipment, even if otherwise desirable, if the accompanying retirement of the old assets will result in a reduction in the "valuation" of the company's properties for purposes of rate regulation. Hence, a management may be impelled to delay the replacement, against the dictates of sound economics, until the cost of the old asset has been completely amortized. The danger of this drag on progressive technology will be reduced if the assets are written down to minimum book values safely ahead of the dates on which they ought to be retired or relegated to stand-by service.[82]

[81] But the qualification just noted may be important. In a brilliant review of the development of modern depreciation theory in America, Mr. George O. May suggests that the development of railroad transportation would have been retarded had the railroads been induced or compelled to practice depreciation accounting from the beginning, with resulting higher early freight and passenger tariffs. *Financial Accounting* (New York, 1943), Chap. 9. A possible reply is that, while early transport development would probably have been slower, it might also have been more rational and more conducive to later technological progress. But a confident appraisal of this historical issue is rendered impossible by the virtual certainty that the adoption of systematic depreciation accounting could not have taken place except in company with many other changes in the direction of "commercial law and order"—changes in financial practice, in business ethics, and in rules of rate regulation of a kind not associated with pioneer days.

From the standpoint of price economics, the danger of excessively rapid capital-cost amortization is that the resulting rates of charge for service may eventually become too low. That is, if these rates, when freed from the burden of fixed charges, should fall below marginal or incremental costs of production (including the costs of necessary increments of plant and equipment), wasteful overconsumption would probably result. See p. 302, *infra*. One may also note the Keynesian argument that rapid depreciation accounting, like rapid public debt amortization, constitutes a "disinvestment" adding to what Lord Keynes thought to be the danger of chronic unemployment. J. M. Keynes, *The General Theory of Employment, Interest, and Money* (New York, 1936), p. 95. Compare the opposing views of Dr. George Terborgh, *The Bogey of Economic Maturity* (Chicago, 1945).

[82] This position would have been challenged by the late Mr. Samuel Ferguson, the distinguished Chairman of the Hartford Electric Light Company, who expressed the fear that straight-line depreciation accounting, combined with the deduction of the resulting depreciation reserve in the measurement of the rate base, would tempt managements to make unjustified, premature replacements. See his "Further Comments on the NARUC Report," 21 *Journal of Land & Public*

One of the many practical virtues of an actual-cost standard of rate control, as distinct from a fair-value standard, lies in its compatibility with a policy of regulation which resolves reasonable doubts about proper annual charges for accruing depreciation in favor of the more liberal charge. Under a fair-value rule, strictly construed, any excess in the depreciation reserve over "actual depreciation," estimated in the light of hindsight, will result in a windfall benefit to the corporate investors even though the reserve reflects funds supplied by the consumers.[24] But under an actual-cost rule, strictly construed, any reserve built up by customer contributions is deductible however far it may exceed the "actual depreciation." The excess in the reserve becomes, in a sense, a "consumer equity," comparable to the consumer equity in publicly owned plants originally financed by bond issues that have already been paid off, in whole or in part, long before the plant has become obsolete.

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QUALIFICATIONS OF THE STATEMENT THAT "ACCRUED DEPRECIATION" REFLECTS RECOUPED INVESTMENT

In the first section of this chapter, "depreciation" as the negative term of the rate base was first defined as amortized cost and then associated with recouped investment. But the reader was warned that the association is not one of complete identity; and it now remains to discuss the reasons for the warning.

The costs of fixed assets can be said to have been "amortized"

Utility Economics 181–184 (May, 1945). But, as Emery Troxel notes, Ferguson's position lacks plausibility or factual support. *Economics of Public Utilities* (New York, 1947), p. 346.

The point of view expressed in the text is similar to that often voiced with respect to depreciation accounting for unregulated business enterprise. That is to say, inadequate rates of cost amortization have been held responsible for undue delays in the making of economically desirable replacements. But with unregulated business, the asserted reluctance of management to replace an old asset prior to its accounting amortization is generally assumed to be irrational; whereas, with public utilities, the corresponding reluctance of management to retire an asset in a manner adverse to the rate base is not irrational in the same sense.

[24] For the leading case illustrative of this result, see Board of Commissioners v. New York Telephone Co., 271 U.S. 23, 31–32 (1926), in which Justice Butler, speaking for the Supreme Court at a time when it was still adhering to the "fair-value" doctrine, declared: "By paying bills for service they [the customers] do not acquire any interest, legal or equitable, in the property used for their convenience or in the funds of the Company."

when they have been gradually written off the plant accounts (or credited to the depreciation reserve as a contra to the plant accounts) through a series of charges to current operations. But the costs thus amortized cannot be said to have been "recouped" unless they have been matched by the receipt of revenues from the sale of the services. What part of these revenues shall be considered cost recoupment and what part income or return on investment cannot be answered with precision except in terms of accounting conventions.[25] Under these conventions, all revenues in excess of those equal to current operating expenses, exclusive of depreciation, are considered *available* for recoupment. But not even these revenues are held to constitute a return of capital beyond the point at which they cover the current depreciation charges. Any additional revenues are treated as income—as a return *on* capital rather than as a return *of* capital.

Accepting the above-noted conventional definition of "recouped investment," one may say that the depreciation reserve of a public utility company reflects capital already recouped if, but only if, it has been built up through charges to previous periods of operation, in all of which periods the company has enjoyed revenues at least equal to its operating expenses including the depreciation charges. In other words, in no year must the company have suffered an operating deficit.

But suppose that a company has suffered such a deficit, as have many of the railroads in years of poorer revenues. In that event, and under the actual-cost principle, should its entire depreciation reserve be deducted from cost new in the measurement of the rate base? Or should the deduction be limited to the cost that has already been recouped?

Partly, no doubt, because the Interstate Commerce Commission has not purported to apply a strict, actual-cost standard of rate control, this question has not often been raised in the literature. But, in my opinion, the entire depreciation reserve should be deducted.

[25] The conventional nature of the distinction between the return *of* and the return *on* capital is emphasized by the refusal of the Committee on Terminology of the American Institute of Accountants to identify depreciation accounting with periodic asset revaluations. This refusal throws doubt on the meaning of a traditional concept of property income as whatever portion of the gross yield of property can be withdrawn without "impairing the capital." As my accountant colleague Professor James L. Dohr reminds me, "impairment of capital" is itself a convention.

This conclusion is in harmony with the general principle, applied alike under a fair-value rule and under an actual-cost rule, that past deficiencies in corporate revenues do not give rise to valid claims for offsetting recoveries in later years. In refusing to grant such recoveries, rate regulation should and does recognize the resulting necessity of giving to companies the somewhat risky opportunity to enjoy higher rates of return than might otherwise be required in order to attract capital. But any resulting higher "costs of capital" are well worth paying for as a means of avoiding the evils of capitalized deficits.[26]

THE DEPRECIATION RESERVE AS A MEASURE OF "ACCRUED DEPRECIATION"

Under a systematical and well-administered program of actual-cost rate regulation, a public utility company's depreciation reserve, as presented in its balance sheet, should reflect capital costs already amortized through previous charges to operation and hence already recouped unless the company has been unfortunate enough to have suffered operating deficits. But this is an ideal situation, and the ideal has not always been realized in actual practice. One reason for its nonrealization is that some commissions, including that of New York State, have not been given the legal power to approve or disapprove rates of depreciation for income-statement purposes, while other commissions possessing this power have lacked the funds or the will to exercise it.

In these situations, the depreciation reserve per company accounts may not be a reliable measure of the costs that the company has already recouped, or has had the opportunity to recoup, from previous consumers. Its place should then be taken by a hypothetical or pro-forma reserve, sometimes called "the reserve requirement." This reserve requirement reflects the reserve that the company would have built up had it embodied in its financial statements methods of depreciation accounting acceptable for rate-making purposes. Not all commissions, however, have made clear what methods they deem acceptable; and in this event they are under at least moral pressure to accept the method (if any) consistently and carefully applied by the company in question, so long as it falls within the limits of recognized good practice.

[26] Compare pp. 92 and 167, *supra*.

TREATMENT OF PROPERTY RETIRED PREMATURELY BY VIRTUE OF EXTRAORDINARY OBSOLESCENCE

In modern regulation, the allowances for "depreciation" both as operating expenses and as deductible reserves are designed to cover so-called functional depreciation including obsolescence and not merely physical deterioration or wear and tear. Hence the allowances must be based on estimates or plausible assumptions as to the effect of obsolescence on useful-life expectancies. But neither a corporate management nor a commission can hope accurately to predict, years in advance of the event, the dates as of which old properties may need to be retired for reasons of "extraordinary obsolescence."

To a material extent, the harm arising from this lack of prophetic vision can be minimized by midstream re-estimates of remaining-life expectancies and hence by reasonable step-ups or step-downs in annual depreciation charges, so that the dates of complete amortization can be made to correspond fairly well to the dates of the actual retirement. This procedure is much more readily employed under "group methods" of depreciation accounting, whereby the premature retirements of some assets are offset by the longevity of other assets in the same group.

But there occasionally arise extreme cases of unexpected obsolescence, in which a company faces the necessity, or at least the economic desirability, of retiring expensive portions of its entire plant and equipment years before it has received a fair opportunity to recover its investment therein under a routine procedure of depreciation accounting. Striking examples of this necessity have arisen in recent years in the gas industry, in which the distribution companies have abandoned their old manufactured-gas plants in favor of the purchase of the much cheaper natural gas from the newer pipeline companies.

Under a strictly construed present-value theory of rate making, the fact that a company may have failed to recover its outlay in outmoded plant should not give it even a shadow of a claim to a recovery of this outlay from future consumers. But under an actual-cost or net-investment principle, the problem illustrated by the premature retirement of the manufactured-gas plant presents a dilemma. On the one hand, the cost principle suggests that a company should receive an opportunity to recover from later customers compensation for all capital outlays for which it has not yet received full compensation from earlier customers. Yet, on the other hand, the same cost principle has usually been held to entitle a company to compensation only for such capital outlays as reflect the costs of property still "used and useful in the public service."

Faced with this dilemma, commissions have tended—wisely, in my opinion—to prefer the former alternative to the latter. Their precise rulings on this issue have not been uniform. But the New York Commission, which accepts a net-investment standard of rate control, has sanctioned the amortization as an operating expense, over a "reasonable" period of time, of capital losses incurred by gas-distribution companies in the premature retirement of manufactured-gas plants accompanying conversion to natural gas.[27] I do not understand, however, that it has also approved the inclusion of these losses, prior to their amortization, in the rate base under the guise of an "intangible asset." This compromise seems illogical; but it may be defended as a workable intermediate position between the complete denial and the full-scale recognition of the claim of a public utility company to post-mortem compensation for capital costs on which it has not received a reasonable opportunity to secure full compensation prior to retirement.

THE PROBLEM OF RETROACTIVE APPLICATION

The acceptability of a company's depreciation reserve as the proper measure of the rate-base deduction for depreciation has been an especially acute issue when the reserve was built up, in whole or in part, before the company had come under the jurisdiction of the regulating commission, or else before the adoption by this commission of its present rules of depreciation accounting. This latter situation was one of general experience in American rate regulation. For in the 1920s and the early 1930s, most commissions, influenced by shortsighted arguments of spokesmen for the gas and electric companies,[28] had approved or acquiesced in a

[27] See the New York Commission's Cases 15613 (Feb. 26, 1952); 15604 (Feb. 19, 1952); 16189 et al. (June 29, 1953). All of these cases concerned change-over to natural gas by the metropolitan gas companies.

[28] As an outstanding exception, the American Telephone & Telegraph Company has long practiced accrued-depreciation accounting on a straight-line basis and has made notable contributions to the development of this accounting through the application of actuarial techniques. But its well-deserved credit for this

modified version of retirement-expense accounting, which rested content with a relatively small "retirement reserve"—a reserve sufficient only to avoid the serious instability in annual reported operating expenses that would result from the immediate charge of all retirements to current operation. In the mid-1930s, the commissions prescribed uniform systems of public utility accounts requiring the practice of accrued-depreciation accounting of the character described in the second section of this chapter. This change left those companies that had practiced retirement-expense accounting with reserves grossly inadequate by the newer standards. There arose a serious problem of retroactive application.

To the best of my knowledge, no writer has yet attempted a country-wide survey of the subsequent rate cases with the object of determining to what extent the burden of the required shift to depreciation accounting may have fallen on the corporate stockholders or on the consumers. Indeed, such a study would necessarily be inconclusive, since so many factors other than rulings on depreciation have determined commissions' rate-making policies.[29] But there is little reason to doubt that, in most jurisdictions, the burden has been shared by both of these interested groups. Fortunately, the problem has grown less and less serious with the passing years because of the gradual build-up of reserves equal, or nearly equal, to modern reserve requirements.[30]

Although most problems of retroactive adjustment have been

accomplishment was sadly marred by its insistence, for a period of years, that the reserves built up, in effect, by charges to its consumers were chronically far in excess of "actual depreciation" and hence should not be deducted in the determination of the "fair value" of its properties for rate-making purposes. See New York Telephone Co. v. Prendergast, 36 F (2d) 54 (1929). [redacted]

[29] One cannot properly assume that, during the period in which the companies practiced retirement-expense accounting, the consumers must have received the benefits of any temporarily lower operating deductions. Regulation in these years was very deficient in most areas and was seriously crippled by the unrealistic rulings of the appellate courts in rate-making valuations under the prevailing doctrine in *Smyth v. Ames*.

[30] In one opinion, the citation of which escapes me, the Federal Power Commission intimated that it would not deduct more than the actual reserve unless it should be *grossly* inadequate. In the Consolidated Edison Rate Case of 1952, 96 PUR NS 194, the New York Public Service Commission found the electric-property depreciation reserves grossly deficient and deducted the higher reserve requirement in the determination of the rate base. But the Commission stressed the fact that, under its governing statute, it had not received any authority to prescribe the company's depreciation accounts.

concerned with inadequate depreciation reserves, the opposite situation has also arisen on occasion. Indeed, it arose in the famous *Hope Natural Gas* case.[31] Before the Hope Company had come under the jurisdiction of the Federal Power Commission, it had enjoyed complete or partial freedom from rate regulation, with the result that the book values in its accounts exercised little or no control over its rates of charge for natural gas. Under a highly "conservative" accounting practice—a practice that may possibly have been due to its control by the Standard Oil Company of New Jersey—it had built up a depletion and depreciation reserve that the Commission found grossly excessive in the light of modern "reserve requirements." Declaring that the reserve, however excessive, nevertheless represented contributions made by past consumers, Commissioner Scott favored its complete deduction from cost new in the measurement of the rate base. But the Commission disagreed and deducted only the "reserve requirement" of $22,328,016, which fell short of the actual reserve by about $18,000,000. Taken in combination with other rulings, adverse to the company, the Commission's action on this issue seems to me to have been wise. But neither this action nor the alternative desired by Commissioner Scott can be rationalized by reference to any grand "theory" of retroactive equities in rate regulation taking place under a change in the rules of the game.[32]

THE DEPRECIATION OR AMORTIZATION OF ACQUISITION-ADJUSTMENT COSTS

Since this chapter is concerned with the depreciation problem under an actual-cost principle of rate making, it has taken for granted the acceptance of actual cost as a "depreciation base"—as the capital cost to be amortized through systematic annual charges to operations. But, as already noted in Chapter XII, "actual cost" is ambiguous; and one source of ambiguity arises with respect to property which, having been constructed to the order of the original operating company at a cost of, say, $10,000,000, has later

[31] 3 F.P.C. 150 (1942). In the case on appeal, the Supreme Court did not take occasion to pass on the merits of this issue. Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

[32] See Robert L. Hale, "Utility Regulation in the Light of the Hope Natural Gas Case," 44 *Columbia Law Review* 488, 503–520 (1944); Henry F. Lippit II, "Net Investment Rate Making—the Deduction for Depreciation," 62 *Harvard Law Review* 1155–1179 (1949).

been acquired by "the present accounting company" for, say, $12,000,000. Which cost is relevant as a measure of the rate base is a question already discussed in this earlier chapter, which concludes that the appropriate answer depends on the reasons for and consequences of the transfer. We must now *assume* an answer to this primary question, since the answer governs any rational treatment of depreciation, at least for purposes of rate control.

Let us first assume a decision that the only relevant cost for rate-making purposes is the original cost of $10,000,000. Under this assumption, $10,000,000 should constitute the depreciation base; and the accounting disposition of the $2,000,000 excess should have no recognized effect in a rate case. Even if the excess cost is gradually amortized instead of being charged in a lump against some kind of a surplus account, the annual amortization charge should be against income, "below the line," and not against operation.

If, on the other hand, the $2,000,000 excess acquisition price (or any part thereof) has been held to be a proper component of the rate base, as reflecting capital devoted to the public service, it should then receive corresponding treatment in the manner in which it should be depreciated or (in other words) amortized. But how rapidly it should be amortized is a difficult question to answer with confidence unless the excess purchase price can be intelligently distributed to the various plant accounts, tangible and intangible. If this is not feasible, an arbitrary rate, such as characterizes accounting practice with respect to some intangibles, may be chosen. But in any event, the amortization should be treated as an operating charge for rate-making purposes—a conclusion which militates against a speed of amortization seriously burdensome to present consumers.

It is my understanding that, for purposes of accounting, the Federal Power Commission has uniformly required the amortization of acquisition-adjustment-account debits over a "reasonable period of time" (typically 10 to 15 years)—not, however, by charges to an operating expense account.[33] But it is also my understanding

[33] Federal Power Commission, *Report on the Reclassification and Original Cost of Electric Plant of Public Utilities and Licensees* (Washington, D.C., 1950). See also the articles by Messrs. Clader, Colbert, Dohr, Kohler, May, and Paton, cited in footnote 33 of my own article, "Contributions of the Federal Power Commission to the Establishment of the Prudent Investment Doctrine of Rate-Making," 14 *George Washington Law Review* 136–151 (1945).

that the Commission has not yet been compelled to decide a rate case in which acquisition-account allowances have been at issue. Pending a decision on rate-making aspects, the Commission's disposition of the accounting question seems to me defensible only on the assumption that it is necessarily of a provisional character.

ALLOWANCES FOR INCOME TAXES UNDER DIMINISHING-CHARGE DEPRECIATION ACCOUNTING

In the public utility field, the most recent important controversy about depreciation has concerned the accounting and rate-making effects of the provisions of Section 167 of the Internal Revenue Code of 1954, permitting business corporations, in calculating taxable income, to use diminishing-charge procedures of depreciation accounting: specifically, a declining-balance method and a sum-of-the-years-digits method. These liberalized tax-accounting allowances were supported in the Congressional committee hearings partly on the ground that they would stimulate business to expand its capital investments, and partly on the ground that they come closer than straight-line depreciation accounting to a reflection of the rates at which most fixed assets actually depreciate in value from the dates of acquisition to the dates of retirement.[34] But many public utility companies have chosen to stress the first point and to ignore the second. That is to say, they have fairly generally decided to take advantage of the diminishing-charge deductions for tax purposes, while resting content with straight-line depreciation procedures for their financial statements and, presumably, for rate-making purposes.[35] As a result, and since they are in an era of heavy plant expansion rather than in an era of stable equilibrium between

[34] Although these two grounds have often been cited as supplying two separate arguments in favor of the accelerated-depreciation provisions of the tax code, they can also be considered as complementary. That is to say, the provisions may have been incorporated in the belief that business corporations would be stimulated to undertake more rapid capital expansion if permitted to claim for tax purposes rates of depreciation equal to the rates at which their assets actually depreciate.

[35] I am informed that many of those industrial companies which use diminishing-charge methods of depreciation for Federal income-tax purposes use the same methods for their own financial statements. Failure of the public utilities to follow suit might be due to refusal by commissions to let them do so. But no serious attempts at persuasion on the part of the companies have yet come to my attention.

acquisitions and retirements, their current Federal income taxes are reduced by the accelerated rate of tax depreciation, whereas their annual allowances for depreciation as reported to the public service commissions remain unaffected.

By way of making accounting adjustments for this discrepancy between their income reports for tax purposes and their income reports for regulatory purposes, many public utilities have sought leave from the various public service commissions to include, as operating charges, the higher income taxes to which they would be subject were they to report taxable income on a straight-line basis. The excess in these "normalized" taxes over current tax liabilities is to be carried to a special deferred-tax account, against which to charge any later, offsetting enhancements in income taxes. This accounting procedure has already been sanctioned by the Federal Power Commission and by perhaps a majority of those state commissions that have yet issued definite rulings on the subject.[36]

But the really important issue is concerned with the rate-making aspects of this accounting problem, and here each of three major alternatives (along with some rather question-begging compromises) has derived support from some commissions. The first position, accepted in Pennsylvania, California, and elsewhere, is that a public utility company which elects to pay income taxes on a diminishing-charge basis of depreciation accounting may receive no allowance for any taxes beyond those for which it is actually liable in a given year. The second position is that a rate-making allowance shall be made for "normalized taxes" as an operating deduction but that no offsetting deduction shall be made in the measurement of the rate base, since the account for deferred taxes is deemed to constitute a restricted surplus and not a reserve representing amortized capital costs. The third position is that (both for rate-making and for accounting purposes) "normalized" taxes shall be accepted as operating deductions but that any excess in such tax allowances over actual taxes shall be credited to a special reserve account, the

[36] The periodical *Public Utilities Fortnightly* undertakes to keep the reader up to date on commission treatment of accelerated depreciation for accounting purposes as well as for rate-making purposes. See, e.g., Owen Ely, "Deferred Taxes—How the Issue Is Working Out in Rate Cases," 62 *Public Utilities Fortnightly* 104–109 (July 17, 1958). See also an address by F. M. Beatty, Partner, Arthur Andersen & Co., before the New York Society of Security Analysts, Oct. 16, 1957: "Current Regulatory Status of Deferred Tax Accounting for Utilities."

amount of this reserve being deducted from cost new in arriving at the rate base just as is the ordinary depreciation reserve.[37]

The second alternative is the one most popular with the public utility industries since, from their point of view, it has the charm of imposing upon the consumers the obligation to pay deferred-tax allowances which, instead of being transmitted forthwith to the United States Treasury, are to be treated as capital investments entitled indefinitely to the enjoyment of a "fair rate of return" for the benefit of the corporate stockholders.[38] In this respect it has the same charm as that once possessed by the practice under which some public utilities would demand straight-line allowances for accruing depreciation while insisting on the deduction of nothing but a minimum "observed depreciation" in the measurement of the rate base. Support for this position of the industry has been forthcoming from the Federal Power Commission [39] and from a few state commissions. But I have never seen a plausible defense

[37] This arrangement was proposed by the company and approved by the commission in the last Commonwealth Edison Company general rate case before the Illinois Commerce Commission: Docket 44391, June 18, 1958, 24 PUR 3d 209. In another case, the same commission, while not deducting the credit to deferred taxes from the rate base, undertook to reach the same or similar results by an adjustment in its rate-of-return allowance, a far less effective alternative. Re Peoples Gas Light and Coke Co., 27 PUR 3d 209 at 227 (1959). The Wisconsin Commission has held that amounts equal to the allowances for deferred taxes must be added to the depreciation reserve—a position defended by its distinguished Chief of Accounts and Finance, A. R. Colbert.

[38] Noting that his company was one of the first public utilities to use the sum-of-the-years-digits method of depreciation for tax purposes, President Walker L. Cisler of the Detroit Edison Company said: "Consequently we have received and will continue to receive through tax deferrals the maximum possible amounts of interest-free capital. At the present time, through rapid amortization and accelerated depreciation, we have invested about $20 millions of interest-free capital, and this figure will assume somewhat larger proportions." Brochure containing address of Nov. 7, 1956, to the New York Society of Security Analysts, Inc., New York City, p. 7.

[39] The Federal Power Commission's position was first clearly set forth in Matter of Amere Gas Utilities Co., 16 F.P.C. 880 (Aug. 29, 1956), where Commissioner Connole wrote a vigorous dissent. The Commission had indirect legal support for this position in a decision of the Circuit Court of Appeals for the District of Columbia: City of Detroit v. Federal Power Commission, 230 F. (2d) 810 (1955), although that case dealt with accelerated amortization under Sec. 168 of the Tax Code, not with liberalized depreciation under Sec. 167. Apart from its assumption that it was under Congressional mandate to give corporate stockholders the direct benefit of the tax provisions, the Federal Power Commission itself seems to have entertained doubts on the merits of the issue. For, in a ruling of July 2, 1956, relative to accounting for Federal income tax accruals under liberalized depreciation methods, after citing the above-noted court decision as "completely controlling," it added that "the extraordinary ability and willingness" of natural gas companies to attract capital might lead it to call Congressional attention to the question whether the incentive provided by Sec. 167 of the Internal Revenue Code is necessary or desirable for the natural-gas industry.

Whatever interpretation may be placed on "intent of Congress," one might suppose that state commissions would not feel bound by this intent in developing rules for the regulation of intrastate utility rates. Yet the utility companies have pressed the Congressional-intent argument on these commissions—not without success in some cases. Ironically, the accounting firm of Price, Waterhouse & Company is reported to have urged the Federal Power Commission to broaden its accounting treatment of deferred taxes so that the views of state regulatory commissions shall not be superseded by Federal rules of accounting! 60 *Public Utilities Fortnightly* 872 (Nov. 21, 1957).

of this claim to the enjoyment of a profit on funds not contributed by the corporate investors. The defense usually offered is that plant expansion financed by these funds enhances management costs and increases the risk factor. But management costs are covered in the allowances for operating expenses, not in the rate of return. And the risk factor (which may even be reduced, not increased, if the company is permitted to accrue a so-called deferred-tax reserve, as it will under Alternative Number 3) is properly taken into account in the allowance of a fair rate of return on capital contributed by the investors. Hence, there is no need to concede to stockholders a return on capital contributed, in effect, either by the taxpayers or by the consumers.[40]

As I see it, the only reasonable controversy as to the choice among the three above-noted alternatives is that between the view that, for rate-making purposes, companies should receive no allowances for taxes other than for actual current taxes, and the view that, if they practice liberalized-depreciation accounting for purposes of income taxation, they should receive an annual allowance for deferred taxes combined with a deduction of the resulting deferred-tax reserve from what would otherwise be the rate base. Here I am convinced that the weight of the argument lies with the latter

[40] As supporting the adverse position just expressed, see City of Alton v. Commerce Commission, 19 Ill. 2d 76, 165 N.E. 2d 513 (1960), overruling a Commission rate-making order which conceded to a water company an operating deduction for deferred taxes without making an offsetting deduction in the determination of the rate base. In a very able opinion speaking for the Court, Justice Schaefer said: "The Commission's order therefore can not stand. Funds generated by accruing deferred tax expenses, and any facilities financed out of these funds, must be excluded from the rate base." 165 N.E. 2d 524. In this case the Court had at first adhered to the "flow-through" principle in denying to the company any rate-making allowance for taxes in excess of current tax liabilities. But it changed its ruling following a petition for rehearing filed by Arthur Andersen & Co., public accountants, as Amicus Curiae: Brief by Max Swiren, Esq. The final ruling permitted the Illinois Commerce Commission to apply what I have called Alternative Number 3 to the problem under inquiry.

position,[41] and this for three reasons: first, that this position is in harmony with the modern tendency to regard straight-line depreciation as erring on the side of a retarded allowance for cost recoupment rather than an excessive allowance as was once often thought to be the case; secondly, that the very practice of taking rapid depreciation for tax purposes tends to reduce more rapidly the actual values of the depreciating assets—namely, their tax-saving values; and thirdly, that unless utility companies are permitted to set up reserves against so-called deferred taxes, thereby protecting themselves against the possible repeal of the diminishing-charge provisions of the present tax law, they are likely to exercise what has been held to be their option to ignore these provisions in favor of the orthodox straight-line tax accounting—an option adverse to the long-run interests of their consumers. Already, indeed, utility companies in Pennsylvania and elsewhere have exercised this option.[42]

Instead of ending this somewhat involved chapter with a summary of its major conclusions, I return to the primary question raised at the beginning—the question as to the relevance of any deduction for "depreciation" in the measurement of a rate base under an actual-cost standard as distinct from a present-value standard. These different standards require different rules for the treatment of depreciation and even require different definitions of "depreciation" as the amount to be deducted from cost new in the determination of the rate base. But it does not follow, as has sometimes been stated or implied, that the allowance for depreciation under an actual-cost standard "has nothing to do" with the decline in the values of the depreciable assets. For even an actual-cost rate base, while not measured by the value of the property at the time of a rate case, should be indirectly related to this value and, especially, should be kept from exceeding the value to a serious extent. The rules for depreciation accounting or capital-cost amortization summarized in this chapter are designed to serve this practical purpose. Hence, the annual allowances for depreciation as an operating deduction are properly designed to reflect the general downward trend in the service values of the depreciable fixed assets during their "irresistible march to the junk heap." To this extent, as in other respects noted in Chapter XI, an actual-cost standard of rate control is not a standard completely devoid of value concepts.

[41] The main argument for a commission's refusal to make any deferred-tax allowance in a rate case—for the so-called flow-through principle—is that, as long as the tax law remains unchanged and as long as additions to depreciable corporate assets exceed retirements, the "tax deferment" will be continuous and hence will amount, in effect, to a permanent tax saving. With qualifications this contention is correct in that a reduction in current taxes below what these taxes would be under straight-line accounting will not later be offset by an increase in these taxes beyond what they would be under straight-line. Robert Eisner, "Accelerated Amortization, Growth, and Net Profits," 60 *Quarterly Journal of Economics* 533–544 (1952); Sidney Davidson, "Accelerated Depreciation and the Allocation of Income Taxes," 33 *The Accounting Review* 173–180 (1958). But under flow-through, the major benefit of the tax reduction would go to the earlier consumers, in the years in which the tax payments have been reduced, instead of being apportioned among consumers more nearly in proportion to their relative responsibility for payments for services resulting in eventual tax liabilities. As an argument against the accrual of a tax-deferral reserve, the permanent-deferral theory is suspiciously similar to the now discredited "plant immortality" theory of depreciation, mentioned early in this chapter, which was once adduced by the utility industry as an argument against the deductibility of accrued depreciation from cost new in the determination of the rate base.

[42] But see Professor Ben W. Lewis's contention that commissions should have the power to deny to companies, for rate-making purposes, any income-tax allowances in excess of the taxes to which they would be subject if they were to choose accelerated depreciation in determining their tax liabilities. "The Duty of a Public Utility to Reduce Its Income Tax Liability by Using Accelerated Depreciation," 35 *Land Economics* 104–114 (1959).

XIV

THE RATE BASE: REPLACEMENT COST AS AN ALTERNATIVE STANDARD

Bearing in mind the fact that, even when modified by price-index adjustments designed to restate past costs in terms of present dollars, the actual-cost basis of rate control is not a value basis, we now turn to the fundamentally different replacement-cost [1] or present-value principle. Let it be noted at the outset, however, that, when strictly interpreted, this principle refers to a paper theory rather than to any actually accepted, operative rule of rate making. Even so, the principle is worth reviewing if only to call attention to the superficial character of its resemblance to that ill-defined measure of reasonable utility rates which goes under the title of the "fair-value" standard.

Chapter XII, on the actual-cost or net-investment standard, first undertook to define this standard in its modern form before considering its claims for acceptance as a preferred basis of rate regulation. In turning to the alternative of replacement cost, the present chapter will follow, in part, a reverse procedure. First will come a brief exposition of the economic argument in favor of replacement-cost rate making; then a discussion of the relevant definition of replacement cost. This seemingly illogical sequence is dictated by the need to consider first the economic philosophy of the replacement-cost principle in order to find any rational grounds for a choice among alternative definitions of the principle, especially for a choice between the legally orthodox tradition in favor of the reproduction cost of a substantially identical plant and the economists' preference for cost of replacement by means of a modern, substitute plant. But the economic philosophy can be stated very briefly here, since it has already been discussed in Chapters IV and VI.

[1] In this chapter, following a widespread practice, I use "replacement cost" and "reproduction cost" as mere synonyms. Those writers who have drawn a distinction have not been in agreement as to what the distinction should be. But there has been a tendency to associate "reproduction cost" with the cost of replacing the existing plant with a substantially identical new plant. An alternative distinction, though one seldom drawn in rate-making literature, would be that between the cost of replacing the *present* output of service and the cost of producing *additional* units of service (reproduction cost).

ECONOMIC ARGUMENT FOR A REPLACEMENT-COST STANDARD

Viewed, then, from the standpoint of price theory, the case for the replacement-cost principle rests primarily on its supposed effectiveness in securing a proper allocation of the country's limited resources of labor, raw materials, and capital as between the production of public utility services and the production of other goods and services. The attainment of such an allocation is one of the major functions of prices in general, including public utility rates—the third of the four functions distinguished in Chapter III. According to the argument now under review, if public utility rates were set at levels higher than would be required by a replacement-cost standard, they would unduly restrict consumption of public utility services, since they would deter consumers from taking the full amounts of service for which they are ready to pay the costs of rendition as measured by current costs of production. On the other hand, if these rates were set below current replacement costs in compliance with the "false" standard of a return on actual cost, they would tend to stimulate a demand for excessive, wasteful consumption. The consumption would be wasteful because the increased output required in order to satisfy the high demand could be produced only at a cost in excess of the price charged for the service.

In thus serving to secure a well-balanced demand for utility services, replacement-cost pricing is supposed to be a better standard than actual-cost pricing, since it is said to reflect costs that are still escapable rather than outlays which, having already been made, cannot be avoided or minimized by any restrictions on future consumption. Even if, for reasons set forth in Chapter VI, this type of price control does not completely adopt the ideal norm of a competitive price, its supporters would claim that it comes as close to this norm as does any feasible yardstick of monopoly pricing.

Thirty years or more ago, the case for the replacement-cost principle, as just set forth in a very sketchy and inadequate manner, was developed with great skill, and with particular reference to railroad rates, by Professor Harry Gunnison Brown of the University of Missouri.[2] Similar views have been expressed by later writers,[3] but they have lacked both the incisiveness and the firmness of conviction that make Brown's earlier analysis a classic in the history of rate regulation.

REPLACEMENT COST OF SERVICE AS THE RELEVANT COST

Persons familiar with this economic defense of the replacement-cost principle, as expounded by Brown and others, will need no reminder that the version of the principle on which it relies is quite different from the one formerly accepted by the Supreme Court under its interpretation of the "fair-value" rule and still apparently accepted in states that retain this rule even after its repudiation as a constitutionally imposed "law of the land." According to the orthodox legal doctrine, estimates of reproduction or replacement cost are germane to a rate case only as evidence or "elements" of the fair value of the properties devoted to the public use. But because of a widely shared confusion as to the precise relevance of a replacement-cost estimate as a possible index of the actual value of replaceable property—a confusion especially prom-

[2] See, e.g., his *Transportation Rates and Their Regulation* (New York, 1916); "Railroad Valuation and Rate Regulation," 33 *Journal of Political Economy* 505–530 (1925) and 34 *ibid.* 500–508 (1926); "Economic Basis and Limits of Public Utility Regulation," 53 *American Bar Association Reports* 717–737 (1928). For a practicing lawyer's defense of reproduction-cost rate-making valuations similar to that of Professor Brown's, see Frederic G. Dorety, "The Function of Reproduction Cost in Public Utility Valuation and Rate Making," 37 *Harvard Law Review* 173–200 (1923).

[3] Expressed usually, however, in support of the contention that public utility rates should be derived from a rate base which makes allowance for a major inflation in general price levels rather than in support of a strict replacement-cost-of-service basis of rate control. See, e.g., William A. Paton and Howard C. Greer, "Utility Rates Must Recognize Dollar Depreciation," 51 *Public Utilities Fortnightly* 333–356 at 335 (1953). "The inescapable fact," declare these writers, "is that utility rates in general are so unjustifiably low that they stimulate more consumption than can be provided by available facilities, retarding the expansion of the services avidly sought by consumers, and hampering the full enjoyment of what could be supplied if charges were more nearly in line with today's price level."

inent in valuations for different legal purposes including tax and condemnation cases as well as rate cases—reproduction cost has usually been taken to mean the hypothetical cost of a substantially identical new plant:[4] one of the same capacity and location, the same size and number of generating units (with electric utilities), the same motive power (with transportation utilities), the same type of telephone switchboards (with telephone utilities), etc., etc. The resulting "valuation" of the property is therefore an economically meaningless application of up-to-date prices to out-of-date properties. Rates derived from such a rate base do not reflect even a serious attempt to follow the general principles of competitive pricing in a dynamic economy. Nor do they avoid the objection that the costs which they reflect are a form of sunk costs even though restated in terms of current unit prices.

Defenders of the principle of replacement-cost rate control would doubtless reply that the criticisms just advanced apply, not to the principle itself but rather to its fallacious interpretation by tribunals and by engineering experts for the public utility companies.[5] But critics of the whole philosophy of replacement-cost

[redacted] the position of Justice Butler, speaking for the Court in McCardle v. I[redacted] Water Company, 272 U.S. 400, 417 (1926). See my *Valuation of Property* (New York, 1937), pp. 1124, 1184. For a different position, see the concurring opinion of Justice Brandeis in th[redacted] the dissenting opinion of Justice Stone in St. Louis & O'Fallon Ry. Co. v. U.S., 279 U.S. 461, 548–553 (1929). In his dissenting opinion in the *Hope Natural Gas* case, Justice Reed attached the following footnote to his reference to reproduction cost as a relevant factor in the determination of fair value: "'Reproduction cost' has been variously defined, but for rate-making purposes the most useful sense seems to be, the minimum amount necessary to create at the time of the inquiry a modern plant capable of rendering equivalent service. See I Bonbright, *Valuation of Property* (1937) 152. Reproduction cost as the cost of building a replica of an obsolescent plant is not of real significance." 320 U.S. 591, 622 (1944). Even in the early cases, commissions and courts declined to assume replacements ~~of an altogether incredible type.~~ For example, in its railroad appraisals under the Valuation Act of 1913, the Interstate Commerce Commission declined to assume the replacement of ties with outdated kinds of wood such as bois d'arc. I. L. Sharfman, *The Interstate Commerce Commission*, Vol. III A (New York, 1935), pp. 161 *et seq.*

In more recent public utility valuations on a replacement-cost basis, the appraisal engineers have offset, to a limited and indeterminate extent, the fallacy of identical-reproduction-cost appraisals by allowances for obsolescence far more liberal than those conceded in earlier years. But offsets of this kind cannot be reliable in the absence of estimates both of the construction costs and of the operating costs of modern, substitute plants.

[5] In 1942, one of these defenders, Mr. Joseph Jeming, described an actual attempt by a public utility company to apply the reproduction-cost-of-service principle in

regulation, whose views I have supported for many years, may fairly raise the question why a fallacy so elementary from the standpoint of appraisal theory can have persisted to this day among rate-making tribunals, almost sixty years after the Supreme Court, in its dictum in *Smyth v. Ames,* had referred to current costs of construction as one of the important "elements of fair value." In part, at least, the answer must lie in a recognition by practical-minded judges, commissioners, and experts, that estimates of the cost that would be incurred in replacing the service by means of a new type of plant if the existing plant were to disappear into thin air are altogether too speculative and too litigious for purposes of feasible administration. When one considers, moreover, that the replacement might well take the form of a change in the very nature of the service, and not just of a change in the design and location of the plant—a change, say, from street cars to buses, from branch-line railroad service to common-carrier truck service, from house-heating by gas to heating by electrically operated heat pumps, etc.—one need not be surprised that the replacement-cost-of-service theory of rate making remains today a paper theory. What goes under the name of a replacement-cost or reproduction-cost principle is a principle (if such it can be called) which, in its concessions to the real or supposed needs of feasible administration, loses the very charm that has endeared it to some of the academic economists.

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a case concerned with the rates for manufactured gas "in a large metropolitan community"—I assume, Brooklyn. "Unfortunately for the complete development of the proposed principle of rate-making, the case was settled before any cross-examination in respect of these studies was conducted and before any rebuttal testimony was presented." "An Actual Application of the Reproduction-Cost-of-Service Principle in Rate Making," 18 *Journal of Land & Public Utility Economics* 188–203 (1942). See also Mr. Jeming's earlier article on the same subject in Vol. 17 of the same journal (1941), pp. 138–150.

It is by no mere coincidence that the company which proposed to make use of the replacement-cost-of-service principle was a manufactured-gas company, since technological progress in that area has been relatively slow. In electric power production, e.g., postwar improvements in efficiency accompanying the use of larger generating units are said to have kept pace with increases in the prices of labor and raw materials. See Mr. Philip Sporn's announcement of his system's decision to buy two 450 megawatt generators: American Gas & Electric Company news release of April 27, 1956. In the telephone field, compare the statement of Mr. George C. McConnaughey, Chairman of the Federal Communication Commission, that "by 1965 about 50 per cent of expenditures for new construction is expected to be in electronic categories." 58 *Public Utilities Fortnightly* 563 (1956).

IDENTITY BETWEEN A REPLACEMENT-COST-OF-SERVICE STANDARD AND A PRESENT-VALUE STANDARD

Before discussing further the limitations of a replacement-cost-of-service principle of rate making, we may note that, in theory, the principle is the same as that of a correctly interpreted present-value basis of rate making. The present service value of the existing plant of a public utility enterprise can be measured by the estimated cost of a modern, substitute plant minus an allowance, traditionally called "depreciation," for the value inferiority of the old plant including any inferiority due to higher operating costs. If the rate base were set at a value thus measured, the deduction for depreciation would offset the higher operating expenses of the existing plant.[8] In actual practice, however, public utility properties are seldom valued in this manner for purposes of rate control. Instead, the valuation is based on a compromise between depreciated actual costs and engineering estimates of depreciated identical reproduction costs. Whether or not the resulting permitted rates of charge for service are higher or lower than those rates which would be called for under a replacement-cost-of-service test must be a matter of almost pure coincidence.

EVEN IF RATES WERE BASED ON REPLACEMENT COSTS OF SERVICE, THEY WOULD STILL NOT CONSTITUTE "OPTIMUM" PRICES

Despite the strong probability that a replacement-cost-of-service principle will never become a widely accepted operative rule of rate making, a serious attempt to go as far in the direction of this principle as practical difficulties permit might still be worth making if the principle itself could qualify, in theory, as a principle of optimum resource allocation. In fact, however, it cannot so qualify, since it identifies reasonable rates with rates sufficient, in the aggregate, to cover total costs of service replacement including a capital-attracting rate of return on the hypothetical investment in a new plant. With a public utility or railroad system still operating at a scale at which further enhancements in rates of output can

[8] See Maurice R. Scharff's discussion of the theory of replacement-cost appraisals in *Technical Valuation,* Jan., 1948, and in 114 *Transactions of the American Society of Civil Engineers* 907–925 (1949); also the articles by Joseph Jeming cited in the preceding footnote.

take place with less than a proportionate increase in operating and capital costs (conditions of decreasing unit costs), such rates will exceed the incremental or marginal costs of the service. Yet, under the economists' theory of optimum pricing, the important relationship between prices and costs is an equality, under equilibrium conditions, between prices and *marginal* costs. Hence, if optimum resource allocation were to be accepted as the primary objective of rate-making policy, as the replacement-cost advocates insist, what would be required is not a mere transfer from an actual-cost standard to a replacement-cost standard, but rather a transfer from *any* standard of total cost to a standard of incremental cost. This transfer could be accomplished only by the aid of tax-financed subsidies as long as incremental costs are less than average total costs.[7]

In view of this theoretical deficiency of a replacement-cost principle of rate control, any claim that it may have for acceptance on grounds of resource allocation must be stated merely in terms of *relative* advantage. That is to say, the claim must rest on a contention that the discrepancies between public utility rates and incremental costs of service, though unavoidable under *any* attempt to make rates as a whole cover costs as a whole, will be reduced if the latter costs are measured in terms of current costs of replacement rather than in terms of costs already actually incurred.

The merits of such a claim cannot be inferred from any a priori theory of cost behavior or cost analysis. Instead, it would have to be put to an empirical test, the validity of which would be limited to the particular type of public utility under review. But if we accept provisionally the usual American assumption that most public utility enterprises, including most railroads, are even today operating under conditions permitting the enjoyment of further economies of scale, and if we also assume that current replacement costs of service would be higher than historical costs, the acceptance of a replacement-cost principle might be a step in the wrong direction.

[7] See Chap. XX. In a debate on the subject with Professor Brown in 1927 (see footnote 11, *infra*), I argued that the logic of his position would call for support of marginal-cost pricing rather than for support of his proposal to make railroad rates cover total replacement costs. Brown's reply, if I understand it correctly, was that marginal-cost pricing for railroad services is financially impractical but that replacement-cost pricing comes as close to the ideal of competitive pricing as is feasible under private ownership.

THE RESOURCE-ALLOCATION ARGUMENT FOR REPLACEMENT COST IGNORES THE TAX FACTOR

The claim on behalf of a replacement-cost standard, to the effect that it will secure a better allocation of resources than can the rival standard of actual cost, is further weakened by a factor seldom taken into account in debates about the relative merits of the two types of rate base, namely, the tax factor. Under our prevailing systems of state, local, and Federal taxation, a material fraction of the revenues received by the railroads and by the private utility companies from the sale of services must be paid out in taxes. For example, in the year 1956, the total taxes reported by the country's larger private electric power companies in their income accounts amounted to more than 21 per cent of gross revenues.[8] In addition, special excise taxes have been imposed at times upon the purchase of electric service, telephone service, and passenger transportation tickets—taxes imposed directly on the consumer but collected and transmitted to the governments by the utility companies.

Viewed from the standpoints of the consumers and of the companies that render utility service, the payment of these taxes is a part of the necessary costs of service. Viewed, however, from the standpoint of the nation or of the community, this payment cannot be relied upon to reflect, even in a rough and ready way, the *social* costs of service rendition—the burdens that the community as a whole could save by refraining from supplying the service. Yet the resource-allocation defense of replacement-cost rate control involves the assumption that the expenses incurred by the private producer of the service reflect social costs.[9]

In the 1920s, when Professor Harry Gunnison Brown wrote his trenchant criticisms of an original-cost standard of rate making,

[8] Federal Power Commission, *Statistics of Electric Utilities in the United States, 1956, Classes A and B, Privately Owned Companies*, p. xv.

[9] It might be argued that the inclusion of taxes in the prices charged for utility services will bring *relative* rates and prices into harmony with *relative* social costs. But this argument would require the dubious assumption of a close comparability between the tax components of public utility rates and the tax components of the prices of nonutility products. The prospective importance of atomic power, to be produced with atomic fuel supplied by the Atomic Energy Commission at prices not closely related to production costs, and to be aided by expensive government-financed research and by government liability of insurance, will throw even more doubt on the reliability of relative enterpriser costs as a measure of relative social costs.

he paid special attention to the danger that this standard would result in too high rates in a period of declining reproduction costs. For many years, however, replacement-cost valuations have been associated with high rather than low valuations, and the critics of the actual-cost principle have expressed the fear that the resulting rates would be too low and hence would encourage wasteful consumption. But if this danger were really believed to exist despite the heavy prevailing levels of utility taxation, the remedy would not need to be sought for by the adoption of a replacement-cost principle of rate making. Instead, it could be secured far more easily and expeditiously by an increase in utility taxes!

WHENEVER ECONOMIC CONDITIONS DISQUALIFY AN ACTUAL-COST BASIS, THEY WILL PROBABLY ALSO DISQUALIFY A REPLACEMENT-COST BASIS

The rate-making philosophy presented by Brown and other economists on behalf of a replacement-cost principle of rate making, though failing in my opinion to support this principle, is much more effective in revealing both practical and theoretical limitations of the actual-cost principle. Under certain conditions these limitations, inherent in *any* sunk-cost standard of rate making, become fatal or, at least, too serious for toleration. But the point that I would now stress is that, in the recent experience of American rate regulation, when these conditions have prevailed, the remedy has seldom if ever been found to lie in a resort to the replacement-cost standard. Instead, the sought-for remedy has taken the form of a departure from, or even of the complete abandonment of, *any* fair-return standard of rate making. Three episodes in the history of rate regulation will illustrate this point, although others will occur to the reader.[10] The first concerns the regulation of railroad rates; the second concerns the regulation of natural-gas rates; the third concerns local-transit fares.

In December, 1927, when railroad valuation by the Interstate

[10] The Supreme Court's review of the California Commission's unorthodox rate-making valuation of the Market Street Railway in San Francisco suggests another case in point. Here the Court sustained the rate order against the charge of unconstitutionality despite the Commission's refusal to concede a return either on actual cost or on replacement cost, its much lower valuation having apparently been based on the price that the City of San Francisco had bid for the property. Market Street Railway Co. v. Railroad Commission, 324 U.S. 548 (1945). The facts were unusual and the decision is of uncertain import as a legal precedent.

Commerce Commission was an extremely live issue, I presented a paper before the American Economic Association defending an "actual-cost" or "prudent-investment" measure of the rate base in preference to a rate base derived from estimated replacement costs.[11] (The railroad carriers themselves were staunchly supporting replacement-cost appraisals.) This paper was followed by several commentaries from other economists, including a dissent by Professor Brown, who came to the defense of replacement cost on grounds summarized in the preceding paragraphs.

The subsequent history of the Interstate Commerce Commission valuations would make a long story, and there is no need to relate it here. But what is important to note is that this history has belied both Brown's assumptions and mine. For in actual practice, rate regulation by primary reference to the standard of a normal "fair rate of return" on *any* rate base has proved unfeasible. Competitive conditions, combined with the early shortsightedness of the railroads in failing to amortize capital costs by reference to anticipated obsolescence, and aggravated by governmental subsidies to road, air, and water carriers, have prevented the railroads from earning a so-called fair return even on depreciated historical costs and have prevented the Commission from making a serious attempt to regulate rates on any such standard of a fair return. In short, the actual experience of the railroads has revealed the limitations of an actual-cost basis of rate control when applied to a highly competitive industry. But this same experience has also revealed the limitations of a replacement-cost standard. Indeed, railroad valuations, if based on current reproduction costs, would be even higher than those based on net investment, with the result that any attempt to apply such a standard would be even more clearly out of the question.[12] This situation has created a rate-making prob-

[11] "Railroad Valuation with Special Reference to the O'Fallon Decision," 18 *American Economic Review, Supplement* 182–205 (1928). A revision of this paper was published under the title "The Economic Merits of Original Cost and Reproduction Cost," 41 *Harvard Law Review* 593–622 (1928).

[12] That is to say, out of the question under any standard of replacement cost or reproduction cost that has ever been applied or that has any likelihood of being applied in the future. Under a "paper theory" of replacement cost, as presented in some of the economic treatises, "reasonable" railroad rates might be derived from estimates of the cost of replacing the service by whatever forms of transport, including possible new railroads of modern design and location, would justifiably be adopted if the nation's transport system were to be planned *de novo*. The acceptance of these rates would then give to the existing railroad properties values

lem as yet unsolved. But the most widely discussed solutions involve the complete or partial abandonment of any fair-return test of reasonable railroad rates in favor of rates designed to meet the actual competition of rival forms of transport without too serious distortions of the railroad rate structure.[13]

For a second illustration of the failure of a replacement-cost standard to cure the deficiencies of an actual-cost standard, one may turn to the regulation of natural-gas prices by the Federal Power Commission. In the *Hope Natural Gas* case, the Commission had included in the pipeline company's rate base its actual net investment in gas-producing properties. Although the Supreme Court accepted this disposition of the problem of allowing for the costs of gas at the wellhead, Justice Jackson wrote a brilliant dissent.

> The prudent investment theory [he wrote] has relative merits in fixing rates for a utility which creates its services merely by its investment. . . . But it has no rational application where there is no such relationship between investment and capacity to serve.[14]

Yet this conclusion did not lead the Justice to support a reversion to a replacement-cost or "fair-value" basis of price control. Instead, it led him to reject *any* rate base as a sound determinant of the commodity component of the price of gas. The Commission, he said, should be left free

based on capitalized estimated earnings–values on which the railroad companies would be earning what might be regarded, in a backhanded way, as a "fair rate of return." Compare an editorial in the March 8, 1954, issue of *Railway Age*, entitled "Suppose Railroading Were a New Industry."

[13] See Chap. IX, pp. 139–142, *supra;* also former Interstate Commerce Commissioner Clyde B. Aitchison's article, "Fair-Return-on-Value-Theory in Rate Making Loses Force," 25 *I.C.C. Practioners' Journal* 11–15 (Oct., 1957). Mr. Aitchison refers to the Interstate Commerce Commission's rate decision in *Ex Parte 206* as having completely overthrown the "fair return on value" test of reasonable rates. Under competitive conditions now facing the railroads, he declares, this test "has proved to be an illusion."

In an earlier draft of this chapter, I incautiously wrote that, today, not even any railroad management would claim that railroad rates could feasibly be fixed at a level that would yield a conventional "fair rate of return" on a reproduction cost appraisal. I was wrong! In 1956, following a holding of the New York Court of Appeals that the statutes governing telephone and transportation rates require the state commission to take into consideration estimates of reproduction costs, the New York Central Railroad, in seeking leave to increase intrastate passenger fares on its Hudson, Harlem, and Putnam Divisions, was reported to have set as its goal a 6 per cent return on the "replacement value" of properties that had acually cost only a fraction of this value to construct. Washington *Star*, Oct. 9, 1956.

[14] 320 U.S. 591 at 649 (1944).

to fix the price of gas in the field as one would fix maximum prices of oil or milk or coal, or any other commodity. Such a price is not calculated to produce a fair return on the synthetic value of a rate base of any individual producer, and would not undertake to assure a fair return to any producer. The emphasis would shift from the producer to the product, which would be regulated with an eye to average or typical producing conditions in the field.

This is not the place to discuss the merits of Justice Jackson's dissent in the *Hope Natural Gas* case, or the merits of the still highly controversial and difficult problem of natural-gas price regulation. His position is cited here merely as another example of the failure of a replacement-cost rate base to meet the practical needs of price control whenever the economic situation is such as to suggest the rejection of an actual-cost standard.

For a third and final illustration we may turn to municipally owned transportation systems. The New York subway system will serve as a concrete example. At the current 15¢ fare the system is now running an operating deficit, and the present management is doing its best to retard the necessity of a further increase in fares by resort, partly, to cost-cutting devices resulting in impaired service outside of rush hours. Any attempt to make the system earn interest on the subway-incurred debt, or to earn "constructive" interest on original construction costs, would be generally conceded to be out of the question. In short, if one includes capital costs as a part of the costs of service, the system must be run at a heavy loss. But by the same token, any attempt to go beyond this point and to secure a return on the high hypothetical replacement costs of subway construction would be even more clearly hopeless. Yet no sane man proposes to shut the subways down, and few would contend that they *ought* to be shut down unless the subway riders are prepared to cover operating expenses plus a fair return or fair interest rate on the current "fair value" of the property.[15] Again we come to the point of this discussion: that the serious limitations of an actual-cost standard of public utility pricing are unlikely to be overcome by a transfer to a replacement-cost standard.

[15] The New York subway situation illustrates the theoretical limitations of the assumption, implicit in replacement-cost rate theory, that public utility services are not worth rendering unless they can be made to yield revenues to cover total operating expenses plus a fair return. See Chaps. VII and XX.

It is perhaps by no mere accident that one looks in vain in the more recent economic journals for any elaborate defense of the replacement-cost theory of rate making such as was forthcoming in the 1920s and 1930s from the skillful pen of Harry Gunnison Brown. Brief statements leaning toward such a defense may still be found; [16] and the public utility trade journals such as *Public Utilities Fortnightly* still carry articles in support of a "fair-value" basis of rate control not clearly distinguished from a replacement-cost basis. But the emphasis is now on the failure of an unmodified actual-cost rate base to give stockholders protection against inflation. The more theoretical, optimum-resource-allocation argument is either left out or else remains very much in the background.

This current loss of interest in replacement cost on the part of the academic economists has several possible explanations. Among the more probable ones, however, has been the emphasis attached by modern "welfare economists" to pricing based on marginal costs, rather than on total costs or average costs, as a basis of sound resource allocation. Even today, to be sure, those economists who would abandon total-cost pricing in favor of marginal-cost pricing are in a decided minority, if one may judge by a count of published articles on the subject. But their arguments have served to take the bloom off the replacement-cost standard as an asserted means of avoiding the defects of a sunk-cost basis of pricing. More promising ways of reducing these defects lie in the manipulation of utility taxation to this end and in the appropriate design of the rate structure.

Among the actual or proposed measures of the rate base discussed

[16] Of the recent statements in support of replacement-cost public utility pricing that have come to my attention, the most interesting ones are from British economists who have urged that the nationalized utility and railroad industries, instead of being under Parliamentary mandate to charge rates designed to cover fixed-charge requirements on debt incurred in the acquisition of properties from their former private owners, should be instructed to cover "notional" interest and depreciation charges on plants valued on a replacement-cost basis. See W. Arthur Lewis, *Overhead Costs* (London, 1949), Chap. 2; the same author's chapter on "The Price Policy of ~~Public Corpor~~ations," in W. A. Robson, ed., *Problems of Nationalized Industry* (New York, 1952), Chap. 10; A. M. Henderson, "Prices and Profits in State Enterprise," 16 *Review of Economic Studies* 13–24 (1948–1949). D. J. Bolton, the leading British expert on electric tariffs, concedes a theoretical case in favor of replacement-cost determination of total revenue requirements for the British Electricity Authority but feels that the resulting excess in revenues over contractual interest requirements would become the target for opposing demands from labor and from consumers. *Electrical Engineering Economics*, Vol. 2: *Costs and Tariffs in Electricity Supply*, 2d ed. (London, 1951), pp. 42–45.

in the last three chapters, the two that seem to me to deserve highest rating are the two versions of the actual-cost standard set forth in Chapter XII: the orthodox form of a net-investment rate base, and a modified form in which the common-stock-equity component of the rate base is restated by the application of a price-index corrective—preferably, by a so-called cost-of-living index. Under favorable conditions, either probably has a better chance of successful operation than has a rate base derived in whole or in part from estimates of reproduction costs. Under unfavorable conditions, no rate base can be expected to yield satisfactory results, since reasonable rates cannot then be identified with rates designed to yield a "fair" rate of profits under *any* definite standard of fairness.

In 1926 Dr. John Bauer, then as now a leading exponent of the prudent-investment principle, closed an article in reply to Professor Brown with a paragraph that brilliantly summarizes the different philosophies underlying, respectively, the use of actual cost and the use of replacement cost as a measure of the rate base. With Dr. Bauer's permission, I quote his statement in concluding these chapters on alternative measures of the rate base.

> Brown has his eyes fixed constantly upon possible economic waste—and quite properly. But he seems to think only or chiefly in terms of possible discrimination between users, or in retarded or overstimulated use of service—all conjectural and improbable consequences—while I see the waste chiefly in the periods of speculation and financial stagnation, in the cross-purposes between public bodies and the companies, the terrific direct costs of regulation, and the failure to achieve economies of operation and better service which would be available through effective regulation and co-operation with the companies, but are lost through the incessant conflict and deadlock over rates.[17]

[17] John Bauer, "Rate Base for Effective and Non-Speculative Railroad and Utility Regulation," 34 *Journal of Political Economy* 479–513 (1926). While I would not go as far as Bauer here went in minimizing the resource-allocation objection to actual-cost pricing, I would emphasize even more than he did the failure of the replacement-cost standard to supply a remedy. Compare Emery Troxel, "Valuation of Public Utility Property—A Problem in Efficient Resource Use and Efficient Regulation," 23 *Journal of Business of the University of Chicago* 1–21 (1950).

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XV

THE FAIR RATE OF RETURN

As noted in Chapter X, the measurement of the rate base is merely the first step in the calculation of a fair return on the cost or "value" of the corporate property. The second step is the allowance of a "fair" or "reasonable" annual rate of return on this rate base. Up to recent years, the percentage rate was usually arrived at in a much more casual or conventional manner than was the rate base, largely because of the absence of that specious aura of expertise and objectivity that has surrounded engineering valuations for rate-making purposes. Since the Second World War, however, rate-of-return specialists have supplied a similar aura to their subject, with the result that, today, the most critical and controversial part of a general rate case is likely to be given over to the conflicting testimony and exhibits of the finance witnesses for the different parties and, sometimes, for the commission or its staff.[1] The conflict is by no means limited to disagreements on questions of fact or prophecy. It also extends to express or implied disagreements as to the very meaning of a "fair" rate of return or as to the relative weights that should be given to multiple standards of fairness.

The present chapter will review briefly the basic controversies about the meaning and measurement of a fair rate of return.[2] Only

[1] "I have been engaged in a lot of these rate cases, a great many of them, and I know that the most difficulty in all rate cases is the setting of the rate of return." Leslie M. Jones, Vice President and General Counsel, Illinois Bell Telephone Co., at a hearing of City Council Committee on Utilities, Chicago, March 4, 1957, transcript, p. 121.

[2] The general treatises on public utility economics or regulation have chapters on the subject. For an excellent monograph on the earlier cases, see Nelson Lee Smith, *The Fair Rate of Return in Public Utility Regulation* (New York, 1932). Ellsworth Nichols, *Ruling Principles of Utility Regulation: Rate of Return* (Washington, D.C., 1955) is a compendium of relevant statements by courts and commissions. Numerous articles on rate of return have appeared in the periodical *Public Utilities Fortnightly*. See its index references to "Return." The quarterly *Land Economics* (formerly *Journal of Land Economics*) has articles on rate of return by Professors Walter A. Morton (May, 1952), E. W. Clemens (Feb., 1954), Lionel W. Thatcher (May, 1954), Fred P. Morrissey (Aug., 1955), and myself (Feb., 1951). See also Paul L. Howell, "The Rate of Return in Air Transport," 24 *Law and Contemporary Problems* 677–701 (Autumn, 1959).

incidentally, however, will it refer to pronouncements on the subject by courts and commissions. Generally speaking, these pronouncements have been couched in language too broad to serve as clear-cut precedents. Commissions, particularly, have usually carefully refrained from accompanying their "findings" as to a fair rate of return in any given case with a disclosure of the methods and presuppositions on the basis of which they have arrived at these findings. In consequence, a rate-of-return witness who himself takes a definite position on some disputed issue of principle —say, on the choice between a historical-cost and a current-cost measure of the cost of debt capital—may later read the commission's rate order and written opinion without being able to discover whether or not his own views on the issue have carried conviction to the tribunal to which they have been addressed. From the standpoint of one who hopes for progress in the development of more rational systems of rate regulation this is a frustrating experience.

In one respect the Supreme Court's renunciation of the fair-value rule of rate making as the law of the land has added to the complexity of the subject. Since this rule purported to set a single, country-wide standard for the measurement of the rate base, it was also taken to carry with it a uniform set of standards for the determination of a fair rate of return. But today the situation is different. For no longer is there a legal requirement of rate-base uniformity throughout the United States, with the result that the question arises whether a rate of return that would be fair if applied to, and under the philosophy of, a net-investment rate base would also be fair if applied to, and under the philosophy of, a higher or lower fair-value rate base. This question is still subject to sharp dispute; and the dispute is all the more confusing because, at least in most states, a so-called "fair-value" rate base is a compromise rate base, thereby lending itself to the application of ambiguous standards of a fair rate of return.

For reasons already suggested in the preceding chapters, this chapter will attempt to clarify the relationship between rate base and rate of return by a threefold division of subject matter. The first section will discuss the determination of a fair rate of return when applied to an actual-cost rate base under assumed conditions of stable general price levels. The second section will remove the assumption of price-level stability in raising the question whether, even under an actual-cost philosophy of rate regulation, allowance should be made for price inflation through adjustments in the rate of return if not in the rate base. Finally, the third section will discuss the question what measures of a fair rate of return are consistent with the acceptance of a fair-value standard of rate making.

THE FAIR RATE OF RETURN ON AN ACTUAL-COST RATE BASE: ASSUMPTION OF STABLE GENERAL PRICE LEVELS

"COST OF CAPITAL" AS THE BASIC STANDARD OF A FAIR RATE OF RETURN

The acceptance of an actual-cost measure of the rate base by no means completely predetermines, as a matter of "logical consistency," the applicable criteria of a fair annual rate of return. On the contrary, a variety of criteria would be applicable; and each of them might be made both fair and workable if applied with skill and with reasonable consistency over a long period of years. Among the possible alternatives would be any of several schemes for differential rates of return on invested capital designed to reward high managerial efficiency and to penalize inefficiency.

Nevertheless, the basic principle of rate making implicit in an actual-cost measure of the rate base goes a considerable distance toward establishing the relevant tests of a fair rate of return. This principle is that of service at cost. Here, in contrast to any supposed norm of competitive pricing, "reasonable" rates of charge for public utility services are held to be rates sufficient, but no more than clearly sufficient, to cover the total costs actually and prudently incurred by a company in supplying these services. Even the fair-value rule of rate making, as interpreted by courts and

commissions, applies this principle in its allowance for operating expenses. But the actual-cost rule attempts to extend the principle, as far as feasible, to the allowed return over and above the annual operating deductions. That is to say, this allowance is itself designed to cover a part of the total costs of service, namely, those costs incurred by the company in securing the necessary capital. Thus the twofold rule that a public utility may charge rates designed to cover its operating costs *plus* a fair return is converted into the apparently simpler rule that the rates of charge shall cover the company's total costs *including* its costs of capital.

This close association—I won't say complete identification—between a fair rate of return and "cost of capital" under an actual-cost standard of rate regulation has the same general claim for acceptance as has an actual-cost measure of the rate base: namely, the claim of compliance with the requirement of credit maintenance and of corporate ability to attract capital on terms favorable to the company and hence to its consumers. For a company that cannot meet its costs of capital, including its fixed charges plus "reasonable" dividend requirements, cannot long continue to supply adequate public utility service to a growing community—not, at least, without violation of express or implied commitments that it has already made in order to secure capital for the construction of its existing plant. In an extreme case, to be sure, failure to cover existing costs of capital may ultimately be cured, from the standpoint of the community, by a drastic financial reorganization under the National Bankruptcy Act or otherwise. But the cure is costly, prolonged, and painful.

With this introduction to the basic concept of a fair rate of return implicit in an actual-cost philosophy of rate regulation, we may now turn to problems of application. It will soon be apparent that the most formidable problem here concerns, not just the technique of measurement but the very meaning of "cost of capital" when applied to that portion of a company's invested capital represented by its common-stock equity.

Derivation of over-all "cost of capital" by the cost-of-capital formula. Even those public service commissioners and financial experts who derive their conclusions as to a fair rate of return in large measure from their estimate of "cost of capital" seldom completely identify their conclusions with their estimates.[3] More often than not, the estimated cost is offered as a *minimum* standard of adequacy, subject to a "judgment-made" additional allowance for possible error, for real but immeasurable items of cost, for "regulatory lag," and even perhaps as a reward for efficient operation. More will be said on this point later. Meanwhile we may sketch very briefly the technique of estimating the so-called cost of capital as it has been developed by financial witnesses and by the expert staffs of a number of regulating commissions including, notably, the Federal Power Commission. This technique involves the use of the "cost-of-capital" formula.

Under this formula, a utility company's total invested capital is expressed as 100 per cent and is divided into percentages representing, respectively (a) the capital secured by the issuance of funded or long-term debt, (b) the capital secured by the issuance of preferred stock, and (c) the capital represented by the common stock.[4] In harmony with familiar principles of corporation finance and with generally accepted principles of rate regulation, any capital investment reflected by retained earnings (earned surplus) is treated as a component of the common stock.

This threefold division of the corporate capital by reference to

[3] This discussion largely follows the more elaborate treatment that I gave the subject as a rate-of-return witness for the Commonwealth Edison Company in 1953 and again in 1957 (Illinois Commerce Commission Cases 41130 and 44391).

[4] Unless a utility company has heavy investments in nonutility assets, this invested capital should approximate an actual-cost or net-investment rate base except for investment in plant under construction, for which adjustments are usually made by the temporary exclusion of the investment from the rate base combined with the later introduction into the rate base of an allowance for "interest during construction" after the plant has gone into service. But if the company has large investments in other business enterprises, there arises the problem of deriving a cost of capital for the utility properties from an estimate of cost of capital to the corporation as a whole. A precise determination of this former, hypothetical cost is impossible; and the best practical solution may lie in a presumption of equality between total cost of capital and cost of utility capital. The obvious deficiencies of this solution suggest one reason why American public utility companies are wisely restricted in their ownership of nonutility assets.

With "composite" public utilities, such as those supplying electricity, gas, and steam heating, the usual, though not the universal, rule (Maryland has supplied one notable exception) has been that each major class of service must stand on its own feet financially. That is, deficient earnings from one class of service may not be made good by the allowance of an excess rate of return to another class. But the determination of differential "fair rates of return" for the different departments of a combined utility corporation, based on estimated risk differentials, presents problems which would be hopeless except for resort to largely arbitrary solutions.

its major sources permits the analyst to compute separately the cost of the debt capital, the cost of the preferred-stock capital, and a cost or cost equivalent of the common-equity capital. The separation is very helpful, since the costs of the two classes of senior capital can usually be computed with a close approach to accuracy, leaving only the so-called cost of the equity component subject to major differences of opinion.

Let us assume, for example, that the company in question has a capital structure composed of 3½ per cent bonds to the extent of 50 per cent, of 4½ per cent preferred stock to the extent of 15 per cent, and of common stock (par value plus earned and capital surpluses) to the extent of 35 per cent. Let us also assume that an allowed return of 10 per cent on the common-stock capital is deemed adequate. The over-all cost of capital will then be computed as follows, in per cent:

	Per Cent of Total Capital	*Annual Cost*	*Return on Total Capital*
Funded debt	50%	3½%	1.750%
Preferred stock	15	4½	0.675
Common-stock equity	35	10	3.500
Over-all computed cost of capital			5.925

The assumed capital structure. In the application of the cost-of-capital formula the first problem concerns the choice of the assumed security structure—an important choice since the computed over-all cost may be much lower when the debt ratio is high than when the common-stock equity is conservatively thick. Having in mind this differential, some analysts base their estimates on what they themselves accept as a "typical" or an "ideal" security structure without regard to the actual capitalization of the company under review. Other analysts prefer to base their calculations on the capital structure as it now stands or as it is expected to stand in the not-distant future.

In my opinion, the latter alternative is preferable in the usual case, since it does not put a company under the temptation to "trade on a thin equity" as a means of enhancing the earnings on its common stock. Indeed, the use of a hypothetical or "typical" cap-

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italization substitutes an estimate of what the capital cost *would be* under nonexisting conditions for what it *actually is or will soon be* under prevailing conditions. But if the existing security structure is clearly unsound or is extravagantly conservative, the rule must be modified in the public interest. *Actual* cost of capital may then be disqualified in favor of *legitimate* cost.

It has sometimes been argued that, aside from income-tax differentials, over-all cost of capital cannot be materially affected by a corporation's security structure, since a difference in structure means merely a difference in the distribution of risks that are constant for the investment taken as a whole. This argument, however, has been belied by market experience, which indicates that, up to some ill-defined limit, utility companies can secure capital on more favorable terms by substantial senior-security financing.[5] It does not follow, however, that the public interest is served by resort to debt ratios high enough to minimize the cost of capital. Lower ratios may well be worth their higher costs by reducing the risks of financial adversities which would have a serious impact on the quality and expansion of the supply of public service. But the question where the line should be drawn between needlessly low and dangerously high debt ratios is subject to major differences of opinion. Thus, in postwar rate cases, the operating subsidiaries of the American Telephone and Telegraph Company have defended the objective of a one-third debt ratio for the consolidated system, whereas various noncompany witnesses (including myself on occasion) have argued that a somewhat higher debt ratio would be justified.

Determination of the cost of senior capital. Having determined the appropriate capital structure, such as the one used above for purposes of illustration, the analyst usually finds no difficulty in computing the cost of senior capital with fair precision. Actual

[5] This, at least, is the conclusion which I reached, several years ago, on the basis of a number of comparative studies of the security yields of various electric or gas-and-electric companies with different capital structures. I take it that most security analysts hold the same conviction. But this position has been sharply challenged by Professors Franco Modigliani and M. H. Miller, partly on theoretical grounds, partly by reference to earlier statistical studies: "The Cost of Capital, Corporation Finance and the Theory of Investment," 48 *American Economic Review* 261–297 (1958). See also comments on this article by J. R. Rose and David Durand, and a reply by the authors: "The Cost of Capital and the Theory of Investment," 49 *American Economic Review* 638–669 (1959). The subject calls for a thorough re-examination.

fixed charges on the debt plus actual dividend requirements on the preferred stock represent the annual cost in terms of dollars. The dollar figures are then converted into percentages of each type of capital as measured by the net contribution which the company has received from the issuance of the bonds and of the preferred stock.

In rate cases, some rate-of-return witnesses have contended that the allowance for interest costs and for preferred-dividend requirements should be based, not on charges actually imposed by securities now outstanding, but rather on the hypothetical cost of doing senior financing under current conditions of the bond and stock market. As will be noted in a later section of this chapter, this position comports with the logic of a reproduction-cost theory of rate control; and it is arguably applicable even to a "fair-value" rate base which gives material, though not controlling, weight to reproduction-cost appraisals.

But in a calculation based on an actual-cost standard of reasonable utility rates, the objective is to determine, not what the senior capital would cost if it had to be secured *de novo*, but rather what it really does or will soon cost in view of the fact that much of it has been secured at an earlier date and under market conditions differing from those prevailing today. For rate-making purposes, this actual or "experienced" cost is significant as indicating what the present company will need in order to meet its interest and preferred-dividend requirements. Hence, the estimated *current* costs of new bond money and of new preferred-stock money are directly relevant only as evidence of the probable costs of new senior issues that the company must contemplate in the near future for purposes of refunding or of new financing.

When the cost of debt capital is taken to mean actual cost rather than hypothetical current cost, company witnesses have argued that this cost should include an allowance designed to amortize, over the lives of the outstanding bonds, any unamortized debt discounts, call premiums, and finance expenses on refunded bonds that have been called prior to maturity for the purpose of interest savings. For income-tax purposes, these prematurity refunding costs are treated as an immediate loss rather than as a deferred charge; and accounting-minded witnesses have urged similar treatment for rate-making purposes. But the other position is defended on the ground that the losses, net of tax savings, should be borne by later consumers and not by the stockholders, since these consumers will be the primary beneficiaries of the refunding action.

Consistently applied, either of these alternative rules of rate making would be tenable and fair. For, if any losses from refunding operations are to fall on the stockholders, in the form of a resulting erosion of corporation surplus, the allowed fair rate of return can be made high enough to compensate stockholders for the risk of exposure to such losses in the future. But there is a practical ground for preferring the other alternative: namely, that a management may well hesitate to call high-yield bonds if the immediate financial loss must fall on the stockholders while the reduction in annual interest charges must be passed on to the consumers.

The problem of estimating the so-called cost of the common-stock capital. The really critical problem in the determination of the over-all cost of capital is that of estimating the cost of the common-stock component, or rather that of estimating a capital-attracting allowed rate of return which can be said to reflect cost in a very loose sense of that word. Here, the primary difficulty lies in the very nature of the common stock of ordinary business corporations, including most American public utility corporations; namely, in the absence of any express or implied commitment as to the rates of dividend. In this absence, the annual cost actually incurred by a company in floating stock issues, whether by rights offerings to old stockholders or by public offerings, is simply indeterminate. Dividend payments are contingent on earnings; yet the allowable amount of earnings is the very objective of inquiry in a rate case. There thus arises a vicious-circle difficulty somewhat similar to that which precludes the acceptance of the commercial or market value of a utility property as a measure of the rate base.

This difficulty could be avoided if American rate regulation were willing to follow the older British practice under which even the common stocks of public utility corporations would be subject to a fixed maximum annual rate of dividends, such as $4 per share or 10 per cent of par value.[6] Each new issue of stock could then

[6] Robert H. Whitten, *Regulation of Public Service Companies in Great Britain*, Appendix F, Vol. 1, Annual Report of Public Service Commission of New York, First District, 1913. For proposed application to American regulation, see Arthur P. Becker, "Fixed Dividends for All Public Utility Stock," 21 *Journal of Land &*

be sold at the highest price that it would command in the current market, and the resulting total annual "dividend requirements" could then be accepted as reflecting the company's costs of equity capital. In prosperous times, to be sure, the company should be given an opportunity to earn revenues in excess of these requirements in order to protect the stability of its regular dividends and also, perhaps, in order to raise new capital. But all excess earnings would then be credited to a dividend-stabilization account or to a special proprietorship account representing "consumer equity." Wisely in my opinion, however, American practice has been adverse both to such a rigid limitation and such a quasi guaranty of distributable public utility earnings. Hence, a public service commission, in its allowance of a reasonable rate of return, lacks any predetermined measure either of required earnings or of required dividends on the common stock.

In a number of rate cases, witnesses on rate of return have attempted to estimate what they have called the "historical cost" of a company's common-stock capital by retrospective studies of the market conditions prevailing at the times of the original flotations.[7] In this manner they have hoped to determine approximately what rates of earnings or rates of dividends the subscribers to the stock must have anticipated as a basis for their willingness to pay the subscription prices. These anticipated earnings or dividends would

Public Utility Economics 243–249 (1945). Dr. John Bauer has advanced a somewhat similar proposal in *Transforming Public Utility Regulation* (New York, 1950), Chap. X, "Establishing Definite Rates of Return." The really serious objection to all of these plans for a definitive rate of return lies in the danger of a resulting loss of managerial incentive. See pp. 262–265, *infra*.

[7] The application of a historical-cost rather than a current-cost standard even to the common-stock capital derives support from Justice Brandeis's dissenting opinion (concurring as to result) in Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U.S. 276 at 304–308 (1923). There the Justice insisted that a rule which would fix the return for capital raised in the past by the rate of return which happens to prevail today "opens the door to great hardships." The hardship objection, I may add, is particularly applicable to the initial investments in relatively young public utility enterprises which, while already enjoying good credit as "seasoned" enterprises, were of a speculative, promotional character in their early stages. Today, the natural-gas pipeline companies supply examples in point.

In earlier years, a very crude way of giving recognition to the seasoning factor was through the allowance for "going value" as a component of the rate base. This allowance is now fortunately out of fashion. But its absence provides one justification for the commission practice of conceding "fair rates of return" sufficiently liberal to permit the shares of well-established utility companies to attain market values substantially in excess of book values.

then be accepted as a measure of the company's current earnings requirements. But any attempt to surmise investor anticipations in different periods of past history is obviously wildly speculative; and so far as I am aware, the procedure is not in good repute with public service commissions.

Substitution of estimates of current cost of common-stock capital for attempts to determine experienced cost. Aware of the absence of any specific dividend requirement or earnings requirement actually imposed upon a public utility company in raising common-stock capital, many analysts, including the present writer, have substituted a so-called current-cost test for an actual-cost test. This they have done by defining the current cost as the rate of return on new common-stock capital, the anticipation of which would be required in order to attract this kind of capital to the company in question under prevailing market conditions.[8] Thus, if a public utility could issue new common stock only on terms which would give subscribers thereto an expectation of earnings on subscription price on the order of 10 per cent per annum, a 10 per cent rate would be taken to represent the current "costs of equity capital." This rate would then be applied to the common-equity component of the existing capital in deriving the company's "over-all cost of capital."

The practical defense of this current-cost test of the cost of common-stock capital, when combined with an actual-cost test of the cost of senior capital, is that a company which succeeds in establishing an earning power sufficient to cover both of these costs, year by year, will be able to meet its actual interest and preferred-dividend

[8] The term "capital-attracting rate of return" contains an ambiguity which I do not recall seeing discussed in the literature. When the analyst finds that the anticipation, say, of a 10 per cent return would attract new equity capital, does he mean that the anticipation of a 10 per cent perpetuity would attract capital? Or does he mean that the investor will be attracted by the expectation of a 10 per cent return for the not-distant future, perhaps for the next few years, to be followed by whatever increase or decrease he thinks may result from later attempts of rate regulation to keep abreast of changes in the prevailing costs of capital? I suggest that he cannot mean the former, since he has no way of finding out what investors would pay for a nonexisting type of public utility security. He must, therefore, mean that investors are content to accept the expectancy of a 10 per cent return in view of their own surmises as to whether this return will go up or go down later on. In most periods, perhaps the most plausible assumption is that, under regulation subject to a flexible rate of return, investors accept the chance of a later increase in the allowed rate of return as an offset to the chance of a later decrease.

requirements while maintaining a dividend record on its common stock sufficiently attractive to permit it to issue more of this stock, from time to time, at prices, net of flotation costs, not less than the per-share book value of the old stock. In this way it can float required amounts of bonds and preferred stock while keeping its capital structure in balance by the issuance of new common stock at prices high enough to avoid "impairing the integrity" of the investments of the old stockholders.

Critics of this procedure, of whom there are many among spokesmen for the public utility investors, have made the point that it inconsistently combines actual-cost with current-cost tests of a fair rate of return.[9] Their contention is correct. But the inconsistency of the combination may well be deemed a virtue rather than a vice, on the ground that it is a necessary means of dealing with the "inconsistency" of American corporation finance in combining fixed-charge securities with common stock entitled to no specified rate of dividends.

In one important sense, moreover, the transfer from an actual-cost to a current-cost measure of the cost of common-stock capital represents only a modification, rather than a violation, of the actual-cost principle of rate regulation. For under the current-cost measure, the market prices of the utility stocks are designed to be kept in a reasonable relationship to their book values and hence to the actual net costs, per share, of the corporate assets. "Reasonable relationship," of course, is question begging, and more will be said on this point in later paragraphs. But, generally speaking, the book values (with allowances for the probable need to underprice new common-stock offerings) should set a floor to the market values in periods of normal business conditions.

For the reasons just suggested, the charge of "inconsistency" does not constitute a valid objection to the determination of a fair over-all rate of return which combines experienced cost of senior capital with estimated current cost of common-stock capital. But other objections cannot be brushed aside so readily; and the one that has greatest weight lies in the extreme difficulty of making a reliable estimate of "current cost" in the sense of a current capital-attracting rate of return. Indeed, the only practical solution of this

[9] See Leonard A. O'Connor, "Some Critical Thoughts on Cost of Capital," 62 *Public Utilities Fortnightly* 93–97 at 96 (July 17, 1958).

difficulty lies in the acceptance of a *liberal* estimate, or else (what really amounts to the same thing) in the allowance of a "fair rate of return" in excess of the rate derived by formula. Otherwise regulation under an actual-cost standard of rate making would seriously threaten the ability of utility companies to keep abreast of their vast requirements for new capital.

Earnings-price ratios as evidence of current cost of equity capital. In estimating what anticipated or allowed rate of earnings on new common-stock capital will or would attract this new capital, the analyst has at his command two relevant types of statistical data: first, a several-years' record of earnings-price ratios both for the stock of the very company under review and for the stocks of comparable utility companies; secondly, a similar record of dividend yields in terms of ratios of annual cash dividends to average annual market prices.

Until very recently, at least, some analysts placed greater reliance on dividend yields as an indication of a capital-attracting rate of earnings than they placed on the earnings-price ratios. This preference was based on almost conclusive evidence that the investment market was then placing much higher values on currently distributed earnings than on reported retained earnings. Having this evidence in mind, the analyst might therefore first use the dividend-yield data to estimate what rate of dividends would need to be paid on the stock of the company in question in order to make the stock worth at least its book value plus an allowance for underpricing. He would then decide what rate of earnings on the common-stock capital would be reasonably called for in order adequately to support the required rate of dividends.

But this procedure was seriously roundabout, and it has now lost most of its claim for acceptance save, perhaps, as a check method. For the more recent studies indicate that the market is now valuing public utility common stocks by reference to total per-share earnings, with no clear, consistent tendency to "discount" retained earnings.[10] Earnings-price ratios therefore now deserve more attention than current dividend yields as evidence of capital-attracting rates of return.

[10] See Fred P. Morrissey, "Current Aspects of the Cost of Capital to Utilities," 62 *Public Utilities Fortnightly* 217–227 (Aug. 14, 1958). The newer attitude toward retained earnings is probably due in part to the growing importance attached by stockholders to the personal income-tax factor. It is doubtless also partly due to the postwar experience of a fairly steady increase in earnings and dividends per share resulting chiefly from the reinvestment of realized earnings. The earlier experience of the gas and electric companies, with their heavy erosions of surplus and enforced capital write-downs coming as an aftermath of holding-company control, had given investors good reason to doubt whether reported retained earnings would be forerunners of increased rates of dividend. The recent initiation by the Commonwealth Edison Company of the practice of "capitalizing" a large share of its retained earnings by the issuance of annual stock dividends will give new interest to the study of the effect of regular stock dividends (as distinct from stock splits) on market prices.

These earnings-price ratios express the relationship between the reported annual earnings per share and the quoted prices of the shares on the stock market. Usually, though not invariably, they are stated in concurrent form, in that the earnings of a given year will be applied to an average of the prices of the stock for that same year. Needless to say, they do not necessarily reflect the anticipated rates of earnings, and hence the prospect of a future flow of dividends, on the basis of which the market price of the stock is supposedly established by the actions of buyers and sellers. Nevertheless, especially when averaged over a period of several years, they are counted on to give some indication of a capital-attracting anticipated rate of earnings. For example, if the analyst finds that the stocks of a group of comparable utility companies have been selling, fairly consistently, at prices ranging around thirteen times reported concurrent earnings (equivalent to an earnings-price ratio of 7.7 per cent), he has a basis for a *tentative* inference that the stock of the company under review will also sell for about thirteen times its earnings after its earning power has been more or less well "established," following the rate case. If this inference is correct, the stock will sell in the neighborhood of its book value if its post-rate-case earnings come to 7.7 per cent of this book value. But there must be a step-up in the allowed rate of earnings to provide for the underpricing and stock-flotation expense involved in the issuance of additional capital stock. A 10 per cent discount for these last-named items is not infrequently held to be reasonable. This discount would bring the estimated minimum "cost of common-stock capital" to 8.55 per cent (7.7 per cent divided by 0.90).

A variant form of this earnings-price technique is sometimes deemed more reliable, especially when applied in a period of rapid expansion of utility capital. Here, the reported earnings per share are related, not to the price quotations on the stock market but rather to the prices, net to the company after underwriting fees and other flotation expenses, at which utilities have actually offered or issued new stock through pre-emptive rights or through underwritten public offerings. These "earnings-net-proceeds" ratios have the advantage of reflecting in themselves any underpricing and cost of financing actually incurred by the utility companies. They must be used with caution, however, in order to guard against the possibility that some new stock issues may have been deliberately underpriced to the old stockholders beyond the dictates of successful financing.

Useful to the analyst as are both of the above-noted types of earnings-price ratios (the earnings-market-price ratio and the earnings-net-proceeds ratio), they have a serious limitation when offered as evidence of a capital-attracting rate of return on equity capital. This limitation is due to the fact that securities are rationally bought and sold, not directly on the basis of earnings already realized but rather on the basis of *anticipated* earnings. It follows that a current or recent earnings-price ratio of, say, 5 per cent, by no means proves a readiness on the part of investors to accept such a slim rate of return on somewhat speculative common-stock commitments. Contrariwise, a current earnings-price ratio of 15 per cent by no means proves that investors count on the continuance of such a handsome rate of return as their price for the contribution of equity capital. Hence, the analyst must consider, to the best of his ability, the extent to which investors may be "discounting" anticipated increases and decreases in corporate earnings per share.

The difficulty faced by the analyst in estimating what allowed rate of return on a company's common-stock capital would bring the market value of the shares into accord with their book values has been greatly enhanced in recent years by the high premiums over book values commanded by many of the public utility stocks in the postwar market. "Growth stocks" like those of Florida Power & Light Company, Florida Power Corporation, and Houston Lighting and Power Company (fast-growing companies operating in jurisdictions notably liberal toward utility investors) have been selling at from two times to more than three times their book values. Indeed, the common stocks of the electric utility companies in general have at times sold at premiums averaging 60 per cent or more over the book values that purport to represent net capital

investment per share. These relatively high prices, which have resulted in current dividend yields as low as 2 per cent in extreme cases, and in earnings-price ratios as low as 5 per cent, almost certainly reflect investor anticipation of a continued upward trend in earnings and dividends.[11]

The problem here under review can be restated as follows. It is the problem of deriving the current cost of common-stock capital to any given company from the earnings-price ratios of the stocks of otherwise comparable companies that themselves may be earning, and expected to earn in the future, rates of return well in excess of their own costs of capital.[12] In such a situation, the shares will command premiums over book value based on the anticipation of corporate ability to maintain excess earnings, not just on existing capital but on a capital to be enhanced partly by a reinvestment of earnings and partly by the issuance of new stock at more than book value.[13] Needless to say, the current earnings-price ratios of stocks of this character do not represent "cost of capital" in any significant sense of that term. Indeed, if the allowed rates

[11] In addition to the discussions of growth factor in the references cited in footnote 2, see Charles Tatham's chapters on public utility stock valuation in Benjamin Graham and David L. Dodd, *Security Analysis*, 3d ed. (New York, 1951), supplemented by his article on "The Growth Factor in Electric Utility Earnings," in the March, 1952 issue of *The Analysts Journal*.

[12] This particular problem might be avoided by deriving the cost of equity capital from a record of earnings-price ratios and dividend yields of the stock of the very company in question, rather than from a set of comparable stocks, as long as this stock has been selling at prices not grossly in excess of book values. But the analyst then runs into another problem: that of determining to what extent the market prices of the stock of the company at bar may be based on an anticipation of an increase or decrease in earning power resulting from commission action.

[13] A study of twenty of the largest electric utility operating companies in the United States indicates that, for the period from 1948 to 1956, average earnings per share increased at a rate equivalent to a constant annual increase of 4.6 per cent per annum (6.6 per cent for the shorter period, 1952–1956). The corresponding average increase in dividends per share was at the rate of 4.4 per cent (5.0 per cent for 1952–1956). Both computations were made after adjustments for stock splits and stock dividends. Testimony of James C. Bonbright, Commonwealth Edison Rate Case of 1957, Case 44391, Illinois Commerce Commission, Edison Exhibits 13.25 and 13.26. In my accompanying testimony I surmised that 60 per cent or more of the growth in per-share earnings was attributable directly to the factor of retained earnings (which had averaged about 30 per cent of earnings on the common stock for the companies under review), and that 40 per cent or less was due directly to increases in net capital investment per share resulting from stock offerings between the beginning and the end of the period. These offerings had yielded net proceeds per share averaging about 133 per cent of the pre-offering book values of the old stock. The twenty selected companies did not include growth-stock companies like those of Florida and Texas.

of earnings on such stocks were to be permanently limited, by commission action or otherwise, to a rate of return on their book values equal only to their present earnings-price ratios, their market values could be expected to fall well below their book values.

So far as I am aware, no adequate solution of the problem just set forth has ever been offered. What makes the problem doubly difficult is that *any* constant, realized rate of return on public utility equity capital will tend to be converted into a continuously increasing rate of earnings and of dividends per share, given the maintenance by the company of a constant dividend-payout ratio (ratio of current dividends to current earnings) of less than 100 per cent, and absent any erosion of corporate surplus. Hence, the deficiency of current earnings-price ratios as measures of current costs of equity capital lies, not in the mere probability that these ratios reflect an investor expectation of subsequent increases in earnings and dividends per share, but rather in the probability that they reflect an anticipation of a rate of increase faster than that within the power of a company whose earnings are limited to its cost of capital.

I conclude this discussion of the difficulty of determining the cost of equity capital for any given company by expressing the conviction that the only such cost that can be determined with confidence is a *minimum* or *partial cost.* That is to say, the analyst, by a study of earnings-price ratios and of other market data, may be able to reach a credible conclusion that the cost of common-stock capital comes to *at least* some specified per cent; but the extent of the probable deficiency is necessarily a matter of surmise. Hence, if the minimum estimated cost is to be used in the determination of a computed "overall cost of capital," the resulting computation should be subject to a material, "judgment-reached" enhancement in order to give reasonable assurance of full-cost coverage.

Should the allowed rate of return be designed to prevent the market prices of public utility equities from rising to substantial premiums above book values? A rigorous and literal application of a cost-of-capital measure of a fair rate of return in the above-outlined sense of this measure would mean an attempt by a commission to regulate rates of charge so as to maintain the market prices of utility equities on a par with their book values or rate-

base values plus some stipulated allowance for necessary underpricing. Yet a mere reference to any such attempt should suffice to suggest its absurdity. In the first place, commissions cannot forecast, except within wide limits, the effect of their rate orders on the market appraisals of the stocks of the companies subject to these orders. But in the second place, whatever the initial market appraisals may be, they are sure to change not only with the changing prospects of earnings but with the changing outlook of a notoriously volatile stock market. In short, market prices are beyond the control, though not beyond the influence, of rate regulation. Moreover, even if a commission did possess the power of control, any attempt to exercise it in the manner just suggested would result in harmful, uneconomic shifts in public utility rate levels.

This situation is recognized even by supporters of a cost-of-capital standard of a fair rate of return, who undertake to meet the difficulty in two ways. First, "current" cost of equity capital is rarely identified with spot cost. Instead, it is taken to mean a normal or average capital-attracting rate of return characteristic of the market of the past several years and typical of the market anticipated in the not distant future. Secondly, the estimated "over-all cost of capital" resulting from the application of this normalized estimate of the current cost of the common-stock capital is seldom accepted as a full measure of a fair rate of return. On the contrary, as already noted, the computed over-all cost is usually taken as a minimum allowance, subject to a "reasonable" upward adjustment for good measure.

It follows that the common stocks of public utilities which actually succeed in earning a "fair rate of return" as derived by a cost-of-capital technique can be expected to command substantial premiums over their book values or rate-base values except in periods of a seriously depressed stock market—premiums well in excess of any customary allowance for the necessary underpricing of new stock offerings. And the question arises whether the prevalence of these excess premiums is persuasive evidence of a corporate earning power higher than enough to give adequate assurance of continued corporate ability to attract the desired amounts of new capital on terms that do not impair the integrity of the existing capital.

In my opinion, the answer to this question is in the negative.

Regulation is simply powerless to assure the purchasers of public utility equities that future corporate earnings will suffice to maintain market prices on a par with book values or with any other dollar figure. Lacking this power, regulation wisely concedes to the public utility industries opportunities for corporate earnings liberal enough to bring to substantial market premiums the stocks of those well-managed companies that actually succeed in realizing these earnings fairly continuously. But while the allowance of a rate of return, during periods of business prosperity, liberal enough to let utility equities command substantial premiums over their book values seems to me to be called for in the interest of long-run corporate ability to meet capital requirements, the question what constitutes a proper *degree* of liberality has not yet received a convincing answer. Indeed, I doubt whether a conclusive answer can ever be found under such an indefinite standard of a fair rate of return as that of a flexible rate designed to rise and fall with changes in the anticipated rates of income necessary to induce new investments of equity capital.

THE ALTERNATIVE TEST OF A RATE OF RETURN EQUAL TO THAT EARNED ON INVESTMENTS IN OTHER ENTERPRISES OF CORRESPONDING RISKS

As outlined in the preceding paragraphs, a cost-of-capital criterion of a fair rate of return is a criterion of credit maintenance and capital-attracting adequacy. The so-called cost-of-capital formula is simply a useful aid in the estimate of rates of return, the systematic allowance of which over extended periods of time is designed to enable a well-managed, soundly financed company to secure needed new capital on terms that are fair to the existing investors.

But the criterion of credit maintenance or capital-attracting sufficiency is by no means the only one that has enjoyed support from courts, commissions, and expert witnesses. One alternative or complementary standard, particularly, has received at least widespread *verbal* endorsement from the appellate courts, following its repeated approval by the Supreme Court: the so-called "comparable-earnings" test. This test was first clearly set forth in the *Bluefield* case of 1923 [14] as applicable to a fair-value rate base. But

[14] Bluefield Waterworks & Improvement Co. v. Public Service Commission, 262 U.S. 679, 692–695 (1923).

it has been repeated in later Supreme Court opinions, even in the majority opinion in the *Hope* case [15] in which Justice Douglas apparently deemed it also applicable to a net-investment rate base. Since the *Bluefield* case is often cited as the leading judicial pronouncement on rate of return, the pertinent part of the opinion in this case, written by Justice Butler, may be worth quoting:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

Here, as in the *Hope* case, are suggested not just one standard of a fair rate of return but two. In the first place, the rate must be equal to that currently earned on "investments" in other equally risky business enterprises. But, in the second place, it must also suffice to maintain the credit and the capital-attracting ability of the very company whose case is at bar. And the question arises what should be done in the likely event that the rate indicated by the one test is higher or lower than the rate indicated by the other. A severely literal construction of the *Bluefield* opinion would seem to require the acceptance of whichever rate of return happens to be higher in any given case. But this interpretation would run so contrary to common sense that it has not won acceptance.

Faced with this problem of judicial interpretation, my own preferred interpretation has been that the courts have not intended to set up two conflicting standards of reasonable utility rates. Instead, the credit-maintenance or capital-attraction standard is primary, while the comparable-risk standard is secondary and ancillary. That is to say, the fair rate of return is a rate, the allowance of which will permit the company in question to support its credit

[15] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, at 603 (1944).

and to raise required supplies of new equity capital on terms fair to the old investors; but this rate is necessarily related to the rates of return that investors, while still free to commit their capital on the competitive market, could expect to secure on investments in enterprises of comparable reputed risk. For the most part, such investments must take the form of the purchase of common-stock equities at prevailing prices on the stock market. What rates of return may be earned by the comparable corporations on their own invested capital, or on the appraised values of their assets, is of no direct concern.

The above-suggested interpretation of the comparable-earnings test seems necessary in order to reconcile it with the other test in the *Bluefield* case—the credit-maintenance test. But one must admit that this interpretation is somewhat strained, and I am not at all sure that it reflects the actual thinking of the judges who have cited the *Bluefield* opinion as a legal precedent. An alternative interpretation, consistent with a present-value standard of reasonable rates rather than with an actual-cost standard, is that regulated enterprises should be permitted to earn on the current values of their corporate assets, as based on replacement-cost appraisals, rates of return similar to the rates actually being earned by unregulated enterprises on the values of their assets, similarly appraised. But even this interpretation is a mere attempt by a layman to spell out a criterion which the Supreme Court itself has never undertaken to rid of its ambiguities.

Quite aside, however, from these ambiguities, the comparable-earnings test can hardly qualify as more than an ancillary measure of a fair rate of return if only because it would impose upon the financial analyst the impossible task of finding a group of unregulated business enterprises, investments in which or by which are comparable to utility investments in their esteemed safety and in the cyclical behavior of their earnings. This does not mean that investments in all industrial companies are necessarily more risky than most public utility investments. Indeed, some of the country's great industrial concerns may be so well entrenched in prestige, organization, and command over their market that their greater vulnerability, if it exists, to competition is more than offset by their freedom from restrictive regulation. But the analyst lacks the means of balancing these offsetting factors.

One type of comparable-earnings test has a real, though limited, usefulness. The rate of return proposed as fair for any given company may be compared to the rates actually earned by similar companies in the same jurisdiction or in other jurisdictions. But this kind of a comparison, while suggestive, is not conclusive in the absence of adequate reasons to assume that the realized earnings of the other companies fall within the range of a fair rate of return.

THE FAIR RATE OF RETURN IN A PERIOD OF BUSINESS DEPRESSION

Most of the detailed development of rate-of-return analysis has taken place since the end of the last war and during a period of high prosperity interrupted only by short recessions that have not seriously affected public utility earnings. But this prosperity may not last forever; and the question may arise, as it did in the severe and prolonged depression of the 1930s, what rates of return will then be deemed "fair," or even whether the whole conception of a "fair" rate of return must give way to the exigencies of an economic emergency.[16] Indeed, this question is pertinent at the present time and despite the lack of imminence of a severe depression. For the adequacy of allowed rates of profit during prosperity must depend in part on anticipated rates of profit or of deficit in depressions.

So far as concerns the more or less regular ebbs and flows of business activity associated with an ordinary business cycle, the generally accepted principle of rate-of-return determination is

[16] See E. M. Bernstein, *Public Utility Rate Making and the Price Level* (Chapel Hill, N.C., 1937); Ralph C. Epstein and John D. Sumner, "Effect of the Depression upon Earnings and Prices of Regulated and Nonregulated Industries," 26 *American Economic Review, Supplement* 36–45 (March, 1936); Ben W. Lewis, "State Regulation in Depression and War," 36 *American Economic Review, Proceedings* 384–404 (May, 1946); David E. Lilienthal, "Regulation of Public Utilities during the Depression," 66 *Harvard Law Review* 745–775 (March, 1933); J. D. Sumner, "Public Utility Prices and the Business Cycle: A Study in the Theory of Price Rigidity," 21 *Review of Economic Statistics* 97–109 (1939); J. D. Sumner, "Public Utility Rate Making in Depression: A Comment," 52 *Quarterly Journal of Economics* 713–717 (1937); Donald H. Wallace, chapters on the structure of prices in regulated industries, Part IV of Monograph No. 32, *Economic Standards of Government Price Control*, Temporary National Economic Committee (Washington, D.C., 1941); National Bureau of Economic Research, *Regularization of Business Investment* (Princeton, 1954), especially section by Edward W. Morehouse on "Regularization of Business Investment in the Electric Utility Industry," pp. 213–281.

fairly clear, although the practice gives rise to difficulties. With rare exceptions, public utility tariffs are not raised and lowered year by year with the object of maintaining a constant or stable rate of return on capital investment. Instead, they are set for the indefinite future, subject to revision possibly in a year or less but more probably only after a period of several years. When a rate case arises, a commission may set rates designed to yield a "fair rate of return" on the average for the next several years and not necessarily for the next twelve-month period. Minor variations above and below this figure, unless they are expected to persist or to grow wider with the passage of time, will be allowed to reverse themselves in later years.

But the occurrence of a major business depression, such as the catastrophic depression of the 1930s, presents a quite different problem, and one that simply cannot be solved in advance by the present fixation of rates designed to yield any predetermined fair average rate of return, counting in the substandard returns (or even the deficits) that may possibly be realized during the next depression, if and when it takes place. At least under the prevailing types of rate regulation, a commission, during a period of prosperity, is pretty well limited to two kinds of action designed to take account of depression possibilities of a severe nature: first, insistence on security structures sufficiently conservative in their use of debt capital to permit public utility companies to remain solvent during periods of substandard earning power; and secondly, approval, during prosperity, of rates of earnings on equity capital which will attract stock subscription from an investment market on warning that even utility companies cannot expect to go through major depressions with unimpaired earnings and undiminished rates of dividend.

Unfortunately, however, the investment market must rest content with a warning of a very indefinite character, since the right of a public utility to an opportunity to earn a conventional "fair rate of return" in the event of another severe business depression is subject to much uncertainty, and since no commission is in a position to commit itself in advance of the event. On the whole, the utility companies were treated very liberally by courts and by most commissions during the 1930s, with the result that their rates of charge were either maintained about at predepression levels or else reduced only to a minor extent—in some cases voluntarily. But

only rarely did the utilities find it feasible or permissible to raise their rates in order to make up for loss of output; and any such violation of good economic sense is not likely to be countenanced in another depression.

Among economists in the 1930s, the view was widely held that recovery from the business depression was being seriously interfered with by the distortion in price relationship resulting from the severe decline in the prices of flexible-price commodities including, notably, farm products, unaccompanied by any comparable decline in the "administered" prices of manufactured commodities and in the charges for public utility and railroad services. This view influenced one of the country's leading commissions, that of Wisconsin, to institute a rate case in which it ordered the Wisconsin Telephone Company to reduce its rates on the order of 10 per cent—a moderate reduction but one that could hardly have been supported by a fair-return rule of the orthodox type. But the order was annulled by the highest state court.[17]

In more recent years, business-cycle experts have become skeptical of proposals to combat a depression by enforced reductions of "sticky" prices, and attention has been turned to other alternatives including the possibility of using the combined machinery of regulation and taxation to encourage private utilities to maintain their construction and equipment budgets even when their existing plants are partly idle because of a temporary drop in the demand for service.[18] Unless a reversion to advocacy of price flex-

[17] Wisconsin Telephone Co. v. Wisconsin Public Service Commission, 232 Wis. 274, 287 NW 122 (1939), affirming lower court reversal of commission order in Re Wisconsin Telephone Co., 13 PUR NS 224 (1936). In this case before the commission, a group of economists, including myself, supported a rate-reduction order. For other rulings on rate of return during the depression of the 1930s, see Ellsworth Nichols, *Ruling Principles of Utility Regulation: Rate of Return* (Washington, D.C., 1955), pp. 141–153.

[18] See a recent symposium of economists on *Policies to Combat Depression*, a report of the National Bureau of Economic Research, New York (Princeton, 1956). But economic fashions may change again! As to attempts to encourage advance construction of plant and equipment by private utility companies during a business depression, see Edward W. Morehouse's paper on "Regularization of Business Investment in the Electric Utility Industry," cited at the end of footnote 16, *supra*. Mr. Morehouse was not optimistic about the feasibility of this encouragement. Compare Michael Gort's study of the extent of flexibility in electric utility capital budgeting: "The Planning of Investment: A Study of Capital Budgeting in the Electric Power Industry," 24 *Journal of Business* 79–95 and 181–202 (1951). During the long depression of the 1930s, the great capital investments in electric power were those made by, or under subventions from, the Federal government, notably, the hydroelectric developments and the rural electrification program.

ibility wins general support from economists, the likelihood of widespread public utility rate reductions in even a severe depression will be remote.

Today, the long period of sustained prosperity in America, interrupted by no recession worse than that of 1957–1958, has turned the interest of economists away from problems of depression economics. No doubt the widely held hope that severe depressions are a thing of the past helps to explain this lapse of interest. But optimistic hope is far from certainty; and modern public utility rate theory suffers from its lack of progress in suggesting answers to the question what to do in anticipation of, and in the event of, a major business depression. The problem is by no means confined to that of the general *level* of public utility rates. It extends to the determination of rational rate *structures* during periods of heavy idleness of labor and of plant capacity, when the relative money costs of supplying utility services are unreliable measures of relative social costs.

POSSIBLE ALLOWANCES FOR THE EFFICIENCY FACTOR

Elsewhere in this volume, attention has been called to what is perhaps the most serious of all of the objections to a cost-of-service standard of reasonable public utility rates—to the objection that, as long as rates are fixed so as to assure even a company under mediocre management that it can cover its costs, including a "fair rate of return," and as long as any higher return is denied even to a company under exceptionally able management, there will be lacking under regulated private ownership a stimulus for efficiency comparable to the stimulus of actual competition. American experience with regulated private ownership hardly justifies the unqualified indictment that some writers have made against it on this score. But a plausible case, at least, could be made for the thesis that what has saved regulation from being a critical influence in the direction of mediocrity and tardy technological progress has been its very "deficiencies" in the form of regulatory lags and in the form of acquiescence by commissions in fairly prolonged periods of theoretically "excessive" earnings on the part of companies whose public repute and whose comparative rates of charge for service have not made them vulnerable to popular attack.

But while a situation of this kind may be tolerable, it suggests

the wisdom of more systematic and deliberate efforts on the part of regulating agencies to distinguish, somewhat as competition is supposed to do, in favor of companies under superior management and against companies under substandard management.[19] The distinction might take the form of an express and publicly recognized differential rate of return—a differential, for example, under which otherwise comparable companies might be allowed a 6 per cent rate of return under standard management, a 5 per cent rate under substandard management, and a 7 per cent rate of return under top-grade management. Objection might be raised to the substandard rate of return, on the ground that it would make bad matters worse.[20] But one might hope that the restriction of a company, by virtue of a commission finding of inferior management, to a minimum rate of return measured, say, by a "barebones" estimate of cost of capital, would become so intolerable to the corporate stockholders that they would soon enforce a change of management.

Proposals along these lines have often been made [21] but have

[19] See Dr. Charles S. Morgan's monograph on the subject entitled *Regulation and the Management of Public Utilities* (Boston, 1923). The paucity of later studies does no credit to the modern theory and practice of public utility regulation.

There is ground for the conviction that the opportunity of a well-managed utility to earn a return *liberally* adequate to attract capital is in the public interest as encouraging rapid technological progress and long-run policies of operation. See a suggestive, but self-serving, study designed to support this point of view, printed under the auspices of the American Telephone and Telegraph Company: *Profit, Performance and Progress—A Study of Regulated and Non-Regulated Industry* (May, 1959).

[20] See the opinion of Commissioner Eddy in a recent rate-increase application by the Rochester Telephone Company: Case 18837, New York State Public Service Commission, July 29, 1958, 24 PUR 3d 262. Here, the relatively high rates and asserted inferior service of the company were attributed, in part, to delay in conversion to dial service. Yet the resulting unhappy service situation, said Commissioner Eddy, "can only be corrected by the expenditure of very large sums of money in the future—money which must be obtained in the marketplace in competition with other utilities." With some exceptions the Commission, on Mr. Eddy's recommendations, permitted the company to file the rate increases which it had requested. Commissioner Blach, dissenting, would have reduced the requested revenue increase on the ground that "The record in the proceeding shows that the Company's service in at least three of its exchange areas is of poor quality."

In some jurisdictions a commission may lack the legal power to deny a rate increase upon grounds of poor service. See a comment on this point by Commissioner Cyrus J. Colter of the Illinois Commerce Commission, reported in 62 *Public Utilities Fortnightly* 410–412 (Sept. 11, 1958). Compare Ellsworth Nichols, *Ruling Principles of Rate Regulation: Rate of Return* (Washington, D.C., 1955), Chap. 20, "Efficiency of Operation and Management."

[21] The best-known schemes designed to stimulate managerial efficiency have been the various versions or modifications of the former British Sliding-Scale-Dividend

never as yet made headway for a number of reasons, two of which deserve notice here. The objection most frequently raised is that, with most public utilities, there is an almost complete divorce between stockholders and managers. Hence, if any system of bonuses and penalties is to be desired, it should be applied directly to the executive officers and not to the shareholders, who probably have no control whatever over financial or operating policy.

This is a plausible argument. But it is not completely convincing, since it oversimplifies the motivation of modern corporate management. A responsible management, while concerned to render good public service "for its own sake," properly regards itself as representing the interests of its security holders and, particularly, of its stockholders. Success in maintaining a stable dividend record in the face of business recessions and in developing a net income that will permit a gradual growth in dividend payments as the business expands and as technology improves is almost certainly a prized goal of many public utility executives. The psychology of loyalty and of approval applies even within the executive offices of the giant corporations.

But a second objection to specific efficiency differentials in rate-of-return allowances is far more serious. It lies in the absence, at the present stage of public utility regulation, of adequate objective tests of relative efficiency in the performance of public services. Crude comparisons of the rates charged for service by different companies, in different areas, are altogether unreliable because of differences in operating conditions, in local costs of labor and fuel, in taxes, etc. Refined comparisons, which undertake to allow for these many differences, are more promising. But up to the present time, the technique of their development has not reached the stage of high trustworthiness.

Until more headway in this development has been made, proposals for the systematic use of efficiency differentials in rate-of-return allowances would probably be premature. Meanwhile, however, commissions, in cases requiring a determination of a fair rate of return, would be well advised to encourage the submission, both

schemes, under which the allowed rate of dividends or rate of return varies inversely with changes in a company's rate levels. See Irvin Bussing, *Public Utility Regulation and the So-Called Sliding Scale* (New York, 1936). Aside from other deficiencies, these schemes have been brought to grief by the forces of price inflation.

by the utility companies and by opposition parties, of relevant evidence on the performance record of the company under review as compared both to the performance of other utility enterprises, public and private, and to the performance of the same company in earlier years.[22]

Even if rate regulation will not find it feasible to make systematic use of differential rates of return as incentives to managerial efficiency, it should at least take pains to avoid rules of rate making that positively penalize stockholders for efficient or otherwise desirable action by the management.[23] An example of such a rule would be one which requires the removal from the rate base of the unamortized costs of assets prematurely retired because of obsolescence, but which permits the retention of these costs in the rate base as long as the assets are not actually replaced by superior substitutes. Another example is that of a rule which allows recovery of the actual interest charges on high-interest-bearing callable bonds as long as these bonds remain outstanding, but which compels the company, if it chooses to call the bonds, to charge off the call premium and the unamortized debt discount as a loss rather than as a financial expense to be recovered in later years. Similar examples of rules or practices that create a head-on conflict between managerial action in the consumer interest and action in the stockholder interest will occur to anyone familiar with American rate regulation.

[22] The feasibility of attempts to devise and apply standards of relative efficiency in the operation (though doubtfully so in the construction) of different electrical utilities was affirmed by Professor Robert T. Livingston of the Columbia University School of Engineering in testimony before the New York State Commission on Revision of Public Service Commissions Law, 1930, *Hearings*, Vol. III, pp. 2414–2423. The Fourth Annual Report of the Power Authority of the State of New York (year 1934) presented an engineering study comparing the costs of distribution of electricity in various municipalities, some served by public plants, some by private companies. Significant comparisons between rates charged by publicly and privately owned utility systems are made difficult by the relative freedom of the former systems, and of the interest on securities issued to finance these systems, from the burden of taxation. See Twentieth Century Fund, *Electric Power and Government Policy* (New York, 1948), esp. Chap. 7. But the attempted solution of difficult problems is the task of modern public utility regulation.

[23] Even under public ownership there is urgent need for devices of accounting control designed to reveal uneconomic practices that might otherwise appear to make a showing of good performance. As the late Professor A. M. Henderson remarked in a study of price policies for the British nationalized utilities, "No pricing policy can do much to ensure economical operation of state enterprises but at least it can avoid doing positive harm." "Prices and Profits in State Enterprise," 16 *Review of Economic Studies* 13–24 at 16 (1948–1949).

THE FAIR RATE OF RETURN ON AN ACTUAL-COST RATE BASE IN A PERIOD OF PRICE INFLATION

All of the rate-of-return problems discussed so far in this chapter would be present in a dynamic economy even in a period of stable price levels. But most periods of American history have not been of this character. Instead, the period since the end of the 1930s has been one of more or less continuous inflation. Even if we measure this inflation by the *relatively* stable Bureau of Labor Statistics Index of Consumer prices, which comes as close as any well-known index to reflecting changes in "the cost of living," the dollar has lost about half the purchasing power that it possessed shortly before the Second World War. Of even more significance for the problem at hand is the expectation, widely held among economists and businessmen, that the long-run trend of prices will continue upward, interrupted perhaps by short-run plateaus or even minor dips during times of business recession. The combination of this recent history and this present anticipation of rising prices has had a decided influence on accepted and proposed measures of a fair return: an influence in the direction of more liberal allowances, measured in terms of dollars, than would otherwise probably be conceded. But in many jurisdictions the influence has been indirect and of uncertain import.

A strictly applied, present-value basis of rate control would make full allowance in the rate base for any definitely established increases in the current construction costs of public utility properties. More will be said on this point in the third section of the present chapter. But what we are now concerned with is a different question: namely, whether or to what extent the common stockholders in public utility companies are entitled to the protection of their "real" income against a fall in "the value of the dollar" even under the general philosophy of an actual-cost principle of rate control. Such protection could be given in either of two ways: (a) through an upward adjustment in the rate base of the type discussed briefly at the end of Chapter XII, or (b) through an index-number enhancement of the nominal, percentage rate of return. But the choice between these alternatives, while not unimportant,

presents only a secondary question, on which I shall comment briefly in a later paragraph. The primary issue is that between those persons who contend, and those persons who deny, that the "fair return" to public utility companies is a return designed to compensate the corporate stockholders for any deterioration (or any *major* deterioration) in the purchasing power of the dollar that has occurred between the time of the original capital investment and the time of a rate case.

Needless to say, the affirmative side of this argument has been pressed with most force by spokesmen for stockholder interests and by public utility counsel and witnesses in rate cases. But it has also received considerable support from disinterested sources. As early as 1945, the late John E. Benton, speaking as counsel for the National Association of Railroad and Utilities Commissioners, declared that, in a severe inflation, an offsetting increase in the rate base or in the rate of return "would be required not only in justice to investors but in obedience to economic law. . . . Investors [he added] simply will not buy utility securities, if they find that progressive inflation operates to destroy progressively their right to receive just and reasonable compensation for the service their properties render." [24]

The above-cited remark by Mr. Benton illustrates the twofold character of the claim for inflation adjustments as presented by company witnesses in rate cases: considerations of "fairness" or "equity" as between consumers and investors; and considerations of financial necessity or expediency. To be sure, these claims are not independent of each other, since the question whether existing investors have a fair claim to indemnity for *past* inflation may be held to depend on the question whether uncommitted prospective investors are willing to supply new capital without receiving any protection against *future* inflation. Nevertheless, the answer to the one issue does not necessarily carry with it the answer to the other. Hence, the two questions may best be reviewed separately: first the question of capital-attracting necessity, then the question of fairness.

[24] From excerpts of an address of Dec. 4, 1945, quoted in a brochure on *The Impact of Inflation on Utility Earning Requirement* by W. J. Herrman, Rate Advisor, The Commonwealth & Southern Corporation (New York), Sept. 1, 1948.

THE PROBLEM VIEWED FROM THE STANDPOINT OF FINANCIAL NECESSITY OR EXPEDIENCY

Viewed from the standpoint of financial expediency, the argument for inflation adjustments in the dollar returns allowed to public utility companies—an argument which should carry with it the admitted desirability of downward adjustments in the event of price deflation—rests on the contention that, unless the utility companies receive assurance of such adjustments in the future, they will not be able to raise adequate amounts of new capital, at least not on reasonable terms, in an investment market convinced of the probability of further inflation and of the unlikelihood of later deflation.

The validity of this contention cannot be proved or disproved by a priori reasoning based on assumptions as to the actions of "rational" investors. But, in an article on the subject published in 1951,[25] I noted the failure of company witnesses and of other advocates of rate-making allowances for price inflation to adduce any convincing empirical evidence of the necessity of such adjustments as a means of preventing the sources of public utility capital from drying up. Since the end of the Second World War, the public utility industries have raised huge amounts of new capital for plant expansion and improvements. Yet, in the face of rising price levels, they have secured most of this capital by the issuance of bonds, debentures, and nonparticipating preferred stocks—securities without any offsets for price inflation. Moreover, up to within the past few years, the bond financing and refinancing was done at interest rates made extremely low by the interest-pegging policies of the United States Treasury.

To be sure, the demonstrated ability of the utility industries to do heavy bond financing during postwar years does not prove their ability to market adequate amounts of common stock without inflation protection, since the market for the bonds has come so largely from financial institutions, notably life-insurance companies and pension funds, with long-term liabilities fixed in dollars. But during this same period the utilities have also raised large amounts of

[25] "Public Utility Rate Control in a Period of Price Inflation," 27 *Land Economics* 16–23 (Feb., 1951).

common-equity capital.[26] And success in equity financing has not been limited to companies operating in "fair-value" states or in states (if any) that make express allowances for price inflation in their calculations of a fair rate of return.

When my 1951 article was written, the operating companies of the American Telephone and Telegraph Company system (The Bell System) were taking the lead in presenting to commissions applications for rate increases based, in part, on claims for inflation adjustments. These claims continue to be pressed with much vigor and with great skill in current rate proceedings. Yet the great success of the parent company in raising unparalleled amounts of new equity capital since the end of the Second World War might be cited as a refutation of any such claim when couched in terms of asserted financial necessity. For the annual rate of dividends was maintained at $9 during every year between 1921 and 1959, with neither a decrease to take account of the price deflation of the 1930s nor an increase to take account of the subsequent inflation. While the stockholders have also received opportunities for supplementary gains through the occasional issuance of "rights," these supplements have not constituted full inflation offsets.[27]

The above-noted postwar history of public utility finance still warrants the conclusion of my 1951 study to the effect "that the alleged necessity of safeguarding utility stockholders against price inflation as a means of attracting new equity capital has not yet been supported by convincing evidence." But even aside from the issue of fairness to investors, the bearing of this negative conclusion on the question whether some such safeguard is desirable is not as clear as one might take it to be. For even in those jurisdictions that

[26] Professor Fred P. Morrissey writes that "the utility industry has accounted for approximately 50 per cent of new equity issues in the post-war period—a trend likely to continue." "Current Aspects of the Cost of Capital to Utilities," 62 *Public Utilities Fortnightly* 217–227 at 217 (Aug. 14, 1958). In an earlier article in the same journal he presented tables on utility bond and stock issues in recent years. "Dividend Policy and Reduction of Tax Liability," 59 *ibid* 15–22 (Jan. 3, 1958). As to future needs for common-stock capital he said (p. 18): "If the predicted expansion is achieved, it is likely that the utilities will be raising at least $600–$800 million annually through stock issues under present methods."

[27] I am informed that, for the period 1946–1957, the subscription rights to convertible debentures and to stock offered to stockholders of the American Telephone and Telegraph Company have had market values equal to an average annual value of about $1.80 per share. This includes the more than $6 value of the 1956 rights to acquire new stock at par ($100).

have not conceded any express inflation adjustments either in the rate base or in the allowed rate of return, most commissions have permitted the public utilities to earn returns sufficiently liberal to support a fairly continuous upward trend in the rates of dividends per share. This favorable trend has been due primarily to the combined effect of a material investment of earnings plus the issuance of new common stock at premiums over book value. In consequence, the owners of many utility stocks, even in original-cost jurisdictions, have not suffered a postwar impairment of their "real" income or a confiscation of their "real" capital, as have the holders of fixed-charge securities or of preferred stocks. Instead, both their annual dividends and the market values of their equities have more or less kept pace with their rising costs of living.[28]

In view of this financial history, the question really at issue is that of a choice between a scheme of rate regulation expressly designed to make the dollar earnings on stock equities rise and fall with changes in general price levels, and the more familiar regulatory practice which makes no direct provision for inflation but which undertakes to compensate stockholders for running the *risks* of inflation by the concession of what might otherwise be needlessly high "fair rates of return." On this difficult question I reserve further comment pending a discussion of the fairness issue.

THE FAIRNESS ISSUE

We come now to the question whether public utility companies are entitled to inflation adjustments in their return allowances on grounds of fairness as between investors and consumers, even assuming that no such adjustments need be conceded for the sake of capital attraction and hence in the long-run interests of the consumers themselves. On this question my own position has not been free from doubt, in view of the fact that the holders of fixed-income investments, including investors in savings banks, U.S. Savings Bonds, and corporate bonds and preferred stocks receive no safeguards against inflation. Of necessity, moreover, the burden of protecting the investors in utility stocks would fall upon all consumers of service, including those whose incomes do not rise with

[28] See Fred P. Morrissey, "Inflation and Public Utility Regulation," *California Management Review*, Vol. I, No. 4, 1959, pp. 74–88. This article is summarized in 65 *Public Utilities Fortnightly* 625–627 (1960).

rising price levels. There is the further serious question whether the extension of escalator provisions, already widely applied in union wage contracts, to public utility stockholders may not tend to accelerate the inflationary spiral.

Not all writers, however, have shared the doubts on the issue that I have just expressed. Among the academic economists, Professor Morton of the University of Wisconsin has not hesitated to denounce, as grossly unfair and as constitutionally confiscatory, the denial to public utility stockholders of income-earning opportunities that make full allowance for experienced price inflation. In an article published in 1952,[29] his strong plea for inflation adjustments designed to protect utility stockholders against the impairment of their "real" capital was presented with such skill and with such moral conviction that it should be read by everyone concerned with the problem. What makes the article of special interest is its concession, contrary to the position taken by other spokesmen for the public utility investors, that inflation protection is not required on grounds of financial expediency.[30]

Without attempting to follow Professor Morton's reasoning, which insists on the traditional character of a common-stock investment even in a regulated corporation, I may here state my own tentative position, reached in the light of his analysis and that of other, more recent writers. In my opinion, the holders of public utility common stocks have a strong claim for the protection of their "real capital" against price inflation in those situations in which they have already been given reasonable grounds to anticipate such protection through the action or inaction of courts, commissions, and legislatures. If the situation were clearly otherwise—if subscribers to public utility common stocks had been on

[29] Walter A. Morton, "Rate of Return and the Value of Money in Public Utilities," 28 *Land Economics* 91–131 (May, 1952). Professor Morton has subsequently defended his position in appearances as a company witness on rate of return in a number of telephone rate cases.

[30] "We can now quickly dispense with the argument that inflation protection is required to attract capital. The need for such protection, we must agree with Professor Bonbright, has not been established. But we can go further and say that it cannot be established. However desirable such protection may be as a matter of fairness, it certainly is not necessary. . . . So long as the nominalistic historical cost–cost-of-money method of rate-making prevails, nothing stands in the way of continuous expropriation of past investors by means of a fall in the value of money. Furthermore, new inflated dollars will always be forthcoming at a satisfactory current yield, except perhaps during times of galloping inflation." *Ibid.*, pp. 117–118. In my own opinion, this was an incautious concession.

actual or constructive notice that, so far as concerns inflation or deflation, they would be treated exactly like bondholders or preferred stockholders—their later claim for inflation adjustment would have no higher moral standing than would a claim for inflation offsets in favor of these other security holders. In states that have adhered persistently to a fair-value rate base, the argument of reasonable anticipation can be urged with much force. But in states that have long adopted an actual-cost rule of rate making, this argument would need to be modified. Here the claim must rest, not on any asserted right to an inflation offset per se, but merely on the right of public utility stockholders to rely on the continued application of whatever liberality, in rate-of-return allowances, the commissions have actually exercised in the past. As already noted, these allowances have sufficed to create a material excess in the market prices of utility equities over their book values. A later reduction in the allowances, designed to bring market values into equality with book values, might well be held to violate reasonable expectations.

The foregoing remarks on the fairness of claims for inflation protection are concerned only with the asserted injustice of rules of rate making to be applied retroactively to stockholders who were justified in anticipating the application of more favorable rules. But what about the fairness of a denial of inflation protection even in the absence of problems of retroactive equities—even, for example, with respect to a new company, the prospective stockholders of which can be put squarely on notice that, in the future, regulation will adhere strictly to the convention of a stable dollar despite any rise or fall in price levels? This is a more difficult question, since traditional standards of financial ethics tend to support the freedom of individual investors to enjoy or suffer the consequences of their own negotiations, subject only to the proviso, embodied in the Federal Securities Act, that they shall be fully informed about the facts of their proposed investment. If these standards are deemed applicable to the problem now before us, a purchaser of common stock in a utility company who buys the stock on notice that he must take his chances of an impairment of his "real income" or of his investment values in the event of further inflation, has no more claim to restitution than has the buyer of a mining stock to the receipt of indemnity for a failure of the mine to produce gold.

If I understand Professor Morton's position, he would not accept this traditional standard of commercial morality when it comes to exposure of public utility stockholders to the "confiscation" of their property through price inflation. This position is worthy of respect. Yet those persons who take it seem to me to lack the strength of their own convictions when they fail to insist that the same standards of equity be applied, at least in the future, to the purchasers of creditor securities and of preferred stocks.[31] The very public utility companies whose officials and expert witnesses complain of the unfairness of a system of rate control which tends gradually to confiscate the "real capital" of their common stockholders, continue to do most of their financing by public offerings of bonds and preferred stocks which are vulnerable to this form of "confiscation" by the express terms of the indentures or of the corporate charters. Indeed, during times of very low interest rates, utility companies have not hesitated to call bonds bearing higher rates whenever they have seen a financial advantage in so doing.

For the reasons just suggested, I do not find the fairness aspect of the case for or against inflation protection as easy a problem as Professor Morton and other writers appear to find it when they insist, almost as if it were self-evident, that public utility common stockholders should receive protection against the gradual or sudden impairment of their "real" capital through a fall in the value of the dollar. The problem is not easy because price inflation, by its very nature, is unfair and disorderly in its impacts on different classes of people, and because any attempt to save one particular class against its inequities runs the risk of imposing even more severe burdens on unprotected classes. It also runs the risk of adding fuel to the inflationary fire.

[31] The late Professor Sumner Slichter was one of the few responsible economists bold enough to have proposed that the U.S. Treasury be authorized to issue savings bonds payable, not in terms of a fixed number of dollars but rather in terms of a specified amount of purchasing power. Others have condemned the proposal as in danger of accelerating the inflationary spiral. Professor Morton suggests that insurance companies would probably not care to buy bonds payable in variable dollars, since their own liabilities are in fixed dollars. This may be true. But the fixity of liabilities on insurance policies and on annuities may be attributed to the unavailability to insurance companies of investments that provide a sufficiently secure inflation hedge. Note, however, the recent proposals for the issuance by insurance companies of "variable annuities," like those of the College Retirement Equities Fund, to be based on investments in common stocks believed to offer protection against price inflation.

But the fairness issue is a close one—so close that I believe that the merits of proposals for systematic inflation adjustments on behalf of utility stockholders should be judged primarily on the basis of capital-attracting efficiency. While the experience down to date indicates that equity capital can be secured without such adjustments, it also suggests that this capital can be secured only by the concession of rates of return that offer to stockholders a kind of compensation for the very absence of protection. This being the probable situation, the provision of overt adjustments, whether in the rate base or in the rate of return, may prove the more satisfactory arrangement, alike to investors and consumers. The possible advantage of this latter arrangement is that the compensation for inflation would then be paid only if, and to the extent that, inflation actually occurs instead of being paid merely in contemplation of the danger that it *may* occur. But the only way to test this possible advantage is by experiment; and the experiment, in my opinion, is well worth trying out in a number of jurisdictions. Perhaps the most promising opportunities in this direction lie in states in which stockholders are already accorded material but unsatisfactory safeguards against inflation by the crude device of a fair-value rule of rate making.

SHOULD INFLATION ADJUSTMENTS BE MADE VIA THE RATE BASE OR THE RATE OF RETURN?

If adjustment is to be made for inflation and deflation (whether as a matter of limited experiment, as I have suggested, or as a matter of general policy, as Professor Morton insists), the question arises whether it should be made in the rate base or in the rate of return. Contrary to the views of some writers, my own preference would be for the former alternative as a means of avoiding the false appearance of an excessive rate of return during a period of inflation. But for reasons already discussed in Chapter XII, this does not mean the adoption of a fair-value rule of rate making. Instead, it means the acceptance of a rate base measured by depreciated actual cost, restated, however, in terms of dollars equal in purchasing power to the purchasing power of the original capital contributions. Moreover, the restatement should be confined to the common-equity capital if the objective is that of maintaining the integrity of the stockholders' investment. Acceptance of this objective would suggest that the index number by which to measure price changes should be neither an index of construction costs nor an index of wholesale prices but rather the Bureau of Labor Statistics Index of Consumer Prices—the closest available approach to a "cost-of-living" index.

As Professor Morton points out in his above-noted article, stockholder protection against inflation could be secured without any enhancement in the annual allowance for depreciation as an operating deduction. True, the latter allowance would then not suffice to let the utility company recoup its original capital investment in dollars of equivalent purchasing power and might therefore seem to subject the corporate stockholder to an erosion of his "real capital." But, from the stockholder's view, the erosion would be prevented by the nondeduction from the rate base of any allowance for accrued depreciation in excess of the "inadequate" depreciation reserve. The important question, therefore, is whether a larger dollar allowance for accruing depreciation, and hence a heavier build-up of the depreciation reserve, is not called for in order to secure a better balance between the claims of present and future consumers. And here, an affirmative answer would clearly be indicated were the issue not complicated by an income-tax law which refuses to recognize deductions for depreciation other than those based on dollar costs.

With an actual-cost rate base, adjusted in the manner just suggested, rate-of-return determination would follow the same general principles suggested in the first section of this chapter. But the return on the common-equity capital (a capital enhanced by the index-number adjustment) would now be designed to bring the market prices of the stock into balance with the *restated* book values. There would still be a need for an excess of market value over revised book value sufficient to allow for underpricing as well as to allow a margin of safety. But there should no longer be a need to concede a rate of return high enough to send stock market prices to the high premiums over restated book values that they enjoy in the present stock market in comparison to their present book values. If such a concession were continued, and if the inflated book values should become a mere base on which to superimpose correspondingly high excess market values, the experience would discredit the whole attempt to provide stockholders with price-level adjustments.

THE FAIR RATE OF RETURN ON A FAIR-VALUE RATE BASE

It remains for this last section to consider what tests of a fair rate of return are applicable to a "fair-value" rate base which gives important weight to reproduction-cost appraisals.[32] This question has been raised repeatedly in the postwar rate cases and has given rise to disputes between those who insist, and those who deny, that the concession of a fair-value rate base in excess of actual net investment should be wholly or partly offset by a lower allowed rate of return. On this issue the positions of the various commissions have been far from uniform. It is my impression that, in fair-value jurisdictions, the general, though not universal, tendency has been to allow less liberal rates of return than would be allowed to comparable companies subject to an actual-cost rate base.[33] But in most cases, the differentials have not been large enough to result in a complete offset.

As to the question whether, as a matter of "theory," the allowed rate of return on a relatively high, fair-value rate base should be lower than the rate allowed on an actual-cost rate base, no intelli-

[32] For case citations, see Ellsworth Nichols, *Ruling Principles of Utility Regulation—Rate of Return* (Washington, D.C., 1955). The public accounting firm of Arthur Andersen & Co. has digested the return allowances and the corresponding types and amounts of the rate base for a great many cases decided since 1914. *Return Allowed in Public Utility Rate Cases,* and two or more *Supplements.*

[33] In a case involving the intrastate New York rates of a gas company that had recently been through a rate case with respect to its operations in Pennsylvania (a fair-value jurisdiction, as distinct from New York which is an actual-cost jurisdiction with respect to gas and electric companies), the company supported a higher rate of return than it had claimed in Pennsylvania. Said the New York Commission: "The reason for the variance in the claims before the respective commissions was not explained of record, but presumably rests upon the commonly accepted generalization that the fair rate of return on an original-cost rate base may be quite different from the fair rate of return on a fair-value rate base." Pennsylvania Gas Co., Inc., Case 17817, Adopted Dec. 17, 1957.

A study of rates of return actually earned by 103 electric utility companies finds that, in 1957, companies in fair-value jurisdictions averaged a 6.25 per cent return on total capitalization as against a 5.43 per cent average for the original-cost companies—an excess of 15 per cent for the former class of companies. In 1953, the excess came to about 12 per cent. *Electrical World,* May 5, 1958, pp. 97–100.

gent answer is possible in the absence of a more definite rationale of the fair-value rule itself than is forthcoming from the opinions of the courts and commissions. But three, quite different, answers have been suggested by some of the recent rate cases, and these will now be discussed in turn.

THE COUNTERVAILING-FALLACY PRINCIPLE

For reasons suggested in the chapters on the rate base, many participants in public utility rate cases, including the present writer, regret the acceptance of a fair-value rule of rate making and would greatly prefer an actual-cost standard, either in its traditional form or else revised by application of index-number adjustments to the equity capital. This aversion to fair value is true of some, though not of all, of those public service commissions that are nevertheless bound to the standard by legal mandate.

Persons of this persuasion are naturally under strong temptation to go as far as the courts will permit in applying an antidote to the fair-value doctrine in the form of an offsetting rate of return. The perfect antidote, of course, would be a precise offset, with the result that a company which establishes a high, fair-value rate base would be allowed exactly the same annual dollar return to which it would be entitled on an actual-cost basis. But the patent subterfuge involved in this allowance suggests its rejection in favor of a partial offset. This procedure invokes a "countervailing fallacy" principle of rate-of-return determination. That is to say, the assumed fallacy of a fair-value standard of rate making is to be counteracted, at least in part, by what would otherwise be the fallacy of conceding less than a capital-attracting rate of return.[34]

Viewed even from the standpoint of persons who object to the fair-value rule of rate making, the wisdom of any such attempt to circumvent the rule by the introduction of an undisclosed "countervailing fallacy" in the measurement of the percentage rate of return seems to me more than dubious. The serious vice of the procedure, of course, lies not in the mere resort to an offsetting

[34] But if one accepts the contention that, as long as the rate base is restricted to actual dollar costs, public utility stockholders are entitled to an enhancement in the percentage rate of return as a protection against inflation, it follows that this enhancement should be removed in the determination of a fair rate of return on a rate base which itself makes allowance for inflation. The use of a lower rate of return to offset the higher rate base is then entirely logical.

fallacy but rather in the lack of a frank and full disclosure. Indeed, if the procedure were to be upheld by the appellate courts despite full disclosure, it could no longer be criticized as a circumvention of the fair-value law since the law itself would then have ceased to exist except as a meaningless and expensive legal ritual.[35]

THE REPRODUCTION-COST PRINCIPLE

If we accept reproduction cost, not just as one "element" of fair value but as the basic standard of rate control, it follows that the "fair rate of return" should also be measured in terms of reproduction cost and not in terms of those costs of capital which the present company is now incurring because it has done part of its financing in a market different from that now prevailing. This statement is subject to whatever qualification may be applied to the determination of the reproduction cost of the property itself. As to this latter cost, it is customary, though not universal, to base the estimates on prices prevailing on the average over a period of several years rather than on spot prices. A similar procedure of averaging might then apply to an estimate of the current costs of capital. But subject only to this qualification, the fair rate of return would depend on whatever anticipated rate would attract new capital to a new enterprise. The most obvious deviation from the calculation applicable to an actual-cost rate base would be the substitution of current costs of debt and preferred-stock capital for the actual costs now incurred by the company by virtue of its outstanding contractual commitments to its senior security holders. Another deviation would be the substitution of a "typical" or "representative" capital structure for the existing structure unless this latter structure is itself deemed typical.

[35] For an approach to full disclosure, see Re Northwestern Bell Telephone Co., 12 PUR 3d 233 (May 31, 1957). Here, the Nebraska State Railway Commission granted a rate increase designed to produce $600,067 additional earnings per annum, which "would enable the applicant to pay reasonable dividends, meet its debt charges, attract additional capital and provide for additions and betterments to its interstate plant and equipment." The resulting earnings, it declared, would be equivalent to a rate of return of 6.2 per cent on a book-value rate base, 4.64 per cent on the company's computed reproduction-cost rate base, 6.3 per cent on a book-value rate base with a lower allowance for working capital than that for which the company contended, and 6.5 per cent on a book-value rate base with no allowance at all for working capital! But the commission did not state which, if any, of these four percentage rates it deemed important for the purpose of its decision, nor did it refer to any ruling on the measurement of the rate base by the Nebraska courts.

But what becomes of the credit-maintenance test of a fair rate of return if the rate-base is to be derived from estimates of reproduction cost and if the "fair rate of return" is to depend, not on the capital costs incurred by the present company but rather on the costs that *would be* incurred by a hypothetical, new company? The answer is that this test is no longer relevant. For, under a reproduction-cost principle of rate making, regulation attempts to simulate the norm of competitive pricing; and a competitive price is not supposed to be based on the financial needs of any one producer. If the given firm cannot maintain good credit while charging such a price, it must either go out of business or undergo financial reorganization. To be sure, the Supreme Court did not express this position when it accepted the credit-maintenance test of a fair return as one of the two tests applicable even under a fair-value rule.[36] But this great Court has not always taken pains to reconcile what it has said about a fair rate of return with what it has said about a rate base.

At the time of writing this chapter (October, 1958), current interest rates are higher than they have been in earlier postwar years, with the result that public utility companies whose outstanding funded debt is still costing them only a trifle more than 3 per cent are now paying from 4 to 4¾ per cent for new debt capital. Under the actual-cost principle of rate control, these higher current rates of interest would affect the fair rate of return on debt capital only to the extent that they affect, or are anticipated soon to affect, the company's annual interest requirements. But under the reproduction-cost principle of rate control, the effect would be immediate, subject to whatever time-period of averaging may be applied in

[36] But the Ohio Supreme Court seems to have accepted this position in its interpretation of the regulatory law of that state. In rejecting appellants' argument, in a telephone rate case, that the dollar amount of the return should be based upon the company's actual "earnings requirement," the court said: "However, under the Ohio Statutes and the decisions of this court, the percentage return is to be related not to the 'total capitalization' or to the 'net investment' but to the statutory rate base (reconstruction cost new less depreciation) so that *neither the actual capital of or net investment in this public utility nor its actual earnings requirements are really material in a proceeding of this kind.*" (Original italics). The court also indicated that, while consideration may be given to "what would reasonably be required" to provide for taxes, interest, dividends on stock, etc., this summation should be designed to measure the requirements of a *hypothetical* company with a property value equal to the statutory rate base of the company under review. City of Cleveland v. Public Utilities Commission of Ohio, 164 Ohio St. 442, 132 N.E. 2d 216 (1956).

the estimate of reproduction cost. Against this enhancement in the current cost of debt capital there may be an offsetting reduction in the cost of common-equity capital if a study of the behavior of stocks of companies in fair-value jurisdictions proves the willingness of investors to accept lower percentage rates of earnings than they would accept for stocks of companies in actual-cost jurisdictions.[37]

THE INFLATION-PROTECTION PRINCIPLE

The competitive-price rationale of a fair-value rule of rate making still enjoys some support in the literature. But it was never taken very seriously by most commissions and courts. And, especially since the time of the *Hope Natural Gas* case in 1944, emphasis has shifted from a simulated-competition defense of the fair-value rule to the more "practical" argument that a rate base in excess of actual dollar costs is called for as a means of protecting public utility stockholders against price inflation. Indeed, the tendency of commissions to set a so-called fair-value rate base which somehow compromises between actual cost and estimated reproduction cost is more in keeping with the latter objective than with the former. For it is consistent with the view that regulation is powerless to protect senior security holders against inflation and hence that only partial allowance should be made for increases in construction costs between the time of construction and the time of a rate case.

To be sure, the retention of the old fair-value rule is a very crude way of maintaining "the integrity" of common-stock investments against a decline in the purchasing power of the dollar. But it has the support of long-standing legal tradition, which an adjusted-actual-cost rule does not have. Moreover, its very indefiniteness

[37] Comparisons of the earnings-price ratios and dividend-yields on the common stocks of electric companies operating in fair-value jurisdictions, such as Pennsylvania and Ohio, with the ratios on the stocks of comparable companies operating in original-cost jurisdictions, such as New York, have supplied no conclusive evidence that the market rests content with a lower current rate of return on the former class of stocks. One may suspect that the market "discounts" the supposed inflation-hedge advantage of an investment in companies operating under the fair-value rule because of serious doubt as to how the rule will be interpreted in the future, or even as to how long it will continue to live against political opposition from consumer interests. For example, bills to repeal the reproduction-cost mandate of the Ohio statutes have been introduced into the state legislature year after year.

gives it a charm in the eyes of those persons who believe in flexible and noncommittal standards of reasonable utility rates.

In any case, this alternative rationale of a fair-value rate base would call for the acceptance of essentially the same tests of a fair rate of return as those applicable to an actual-cost rate base revised by an index-number adjustment of the common-stock capital. The senior-capital component of the over-all cost of capital would then be based on experienced cost rather than on hypothetical current cost, whereas the common-stock component would receive an allowed rate of earnings designed to keep the market prices of the shares, during periods of prosperity, from falling below their net rate-base values plus allowances for underpricing. But the rate of return should include no allowance for price inflation, realized or anticipated, since any such allowance would be incorporated in the rate base.

HOW ARE FAIR RATES OF RETURN ACTUALLY DETERMINED BY PUBLIC SERVICE COMMISSIONS?

Readers familiar with the actual practice of American rate regulation need no reminder about the uncertain relationship between the supposed "principles" of rate-of-return determination as set forth in this chapter and the considerations that actually lead commissions to allow whatever rates of return they do allow in specific rate cases. In the opinions that accompany their rate orders, commissions seldom attempt to disclose the reasons why they find, say, 5.85 per cent fair in one case and 6.2 per cent fair in another.[38] Especially in fair-value jurisdictions, some of the decisions lead one to suspect that the commissions have first reached a conclusion as to reasonable revenue requirements in terms of dollars per annum and then have proceeded to translate these requirements into whatever combination of a rate base and a percentage rate of return will be likely to pass muster with the appellate courts or with public sentiment.

The most significant generalizations about rates of return under

[38] See, e.g., Re Michigan Bell Telephone Co., 20 PUR 3d 397 (Aug. 6, 1957), in which the Michigan Public Service Commission approved a rate increase designed to yield 6.6 per cent on a net investment rate base. In a dissent contending that a higher rate of return was justified, Commissioner Hunt remarked: "This 6.6 per cent is the return adopted by the majority opinion, but not on the basis of staff testimony. The basis of the majority for arriving at this figure is not clearly stated in their opinion."

American regulation are those based on gross and net income reported as actually earned by the different classes of utility companies. During postwar years, the country's electric utilities, for example, have enjoyed a return averaging about 6 per cent on their invested capital, and a net income after dividends on preferred stock averaging about 10 per cent on their common-stock capital.[39] But the ranges on both sides of the average have been fairly wide, and writers have sometimes classified the electric companies by reference to these ranges. Thus, average rates of return on invested capital have been higher in fair-value states than in actual-cost states, higher for small companies than for very large companies, higher for utilities in fast-growing areas such as Florida than for utilities in slower-growing areas like New England, and higher for companies under the jurisdiction of notably "liberal" commissions like that of Florida than for companies under strict commissions like that of Wisconsin.[40] It is my impression—although I have seen no comprehensive statistical data to this effect—that there is a low correlation between relative rates of return on invested capital and relative prices charged for electric service. What correlation exists may possibly be negative[41]—a situation which would be well worth a careful study (a superficial study would be inconclusive) in an effort to trace any cause-and-effect relationships.

I close this last chapter on rate-level determination by suggesting that the real differences among the different jurisdictions are not based on the textbook distinction between an actual-cost principle

[39] For the period 1948–1956, the rate of return on the composite invested capital on the U.S. private electric utility industry, as derived from Federal Power Commission statistics for Classes A and B companies, has averaged 6 per cent per annum, while the rate of earnings on the common-stock equity has averaged 10.4 per cent. Commonwealth Edison Company Rate Case 44391 before the Illinois Commerce Commission (1957), Edison Exhibits 13.5 and 13.7. The computed return on invested capital includes interest during construction; and the invested capital for each year is taken as the mean of the year-end figures.

For the telephone and gas utilities (pipelines and distribution companies) the average rates of return on invested capital have been somewhat higher, at least during the past several years.

[40] See the study in the *Electrical World* cited in footnote 33, *supra;* also Fred P. Morrissey, "Relation of Growth and Rate of Return for Utilities," 60 *Public Utilities Fortnightly* 361–373 (Sept. 12, 1957).

[41] See "Bills Are Lower with 'Fair Value,'" 149 *Electrical World*, June 16, 1958, pp. 71–74.

of rate making and a reproduction-cost or present-value or competitive-price principle. On the contrary, *all* the commissions administer, with more or less efficiency or laxity, versions of, or minor deviations from, an actual-cost or sunk-cost standard of reasonable utility rates. True, there are important, perhaps critical, differences in administration. But these are not differences in the basic theory of "reasonable" or "optimum" rates. They lie rather in different degrees of liberality in the rates of return that companies are allowed to enjoy *on their actual capital investment;* in the differences between painstaking and lax application of the requirements that rates must be reasonable; in the extent to which the legally imposed rules of rate-base determination place a burden on effective and expeditious rate regulation; and in the degree to which and manner by which allowance is made for price inflation in the determination of a company's current revenue requirements.

PART THREE

The Rate Structure

XVI

CRITERIA OF A SOUND RATE STRUCTURE

Despite its recognized importance as a basis of rate control, the determination of revenue requirements under a fair-return standard, which was the subject of the preceding chapters, by no means exhausts the issues of a rate case. For even if this standard were accepted as the master rule of rate making, overriding all conflicting rules such as that against unjust discrimination—an exalted status which, though sometimes claimed for it, it does not enjoy in fact—there would still remain the question what specific rates will yield a fair return, together with the further question what rates and rate relationships should be chosen when a company's earning power is so high that any one of a variety of tariffs could be made to yield adequate over-all revenues.[1]

[1] As noted in Chap. IX, the Interstate Commerce Commission has given far more attention to rate relationships than to rate levels. But the contrary emphasis has characterized the utility rate cases before the state public service commissions. As to the specific rates, the major concern of these commissions has been to protect the interests of the residential customers. In the words of Russell E. Caywood, "The thought is that the larger customer can protect himself, whereas the small customer requires the help of a third party." *Electric Utility Rate Economics* (New York, 1956), p. 4. But in recent years particularly, very large industrial customers have intervened actively in rate cases, not just with respect to the relative height of their rates, but also with respect to the form: e.g., in the Commonwealth Edison Company Rate Case of 1957–1958 before the Illinois Commerce Commission (Case No. 44391), 24 PUR 3d 209.

Public utility counsel have sometimes argued that once a company's total revenue entitlements have been determined by a commission, the choice of a pattern of rates that will yield the allowed revenues should be left to the discretion of the management, which will then be in an impartial position to make a fair apportionment of burdens among its different classes of customers. This is only a half-truth argument: among other reasons, because a utility company is concerned not just to secure rates that will presently yield the approved "fair rate of return," but to develop a pattern of rates that will promote growth of earnings and that will protect these earnings against business depressions. The better the utility management, the greater is this long-run concern.

A much more plausible reason for caution on the part of a commission in over-

We turn now to principles of rate making designed to throw light on these two other questions, but particularly on the latter. By what basic standards, for example, shall regulation pass judgment on a system of electric-utility rates which allows liberal discounts for incremental blocks of energy; or which levies higher charges, per kilowatt-hour, on residential consumers than on industrial customers; or which concedes lower rates for off-peak consumption than for consumption at peak-time hours or seasons? With the telephone utilities, does public policy justify the practice of the industry in setting higher rates for service in larger communities than for comparable service in small communities even when these differentials are not based on differences in cost of service? And what are the merits of the contentions, advanced by some economists but enjoying no popular support, that rush-hour fares for local-transit service or commuter railroad service should be higher than fares at nonrush periods? These are mere random samples of the many practical issues falling under the subject of rate structure.

But rate-structure problems are far more complex than problems of a fair return even though the latter are by no means elementary; and they are even less amenable to solution by reference to definite principles or rules of rate making. In part, the complexity is due to the mass of technical detail, including the technology of metering, involved in the design and administration of workable rate schedules for different types of utility enterprises. In part it is due

riding the rate-pattern policies of a utility company is the one suggested many years ago by Dr. G. P. Watkins, in expressing regret that few American commissions had contributed substantially to the development of principles of electric-rate design. "This situation," he wrote, "is perhaps partly due to doubt as to the possession of adequate powers, but more fundamentally to the diffidence of commissioners when confronted with a subject so complex, both theoretically and practically, as that of electric rates." *Electrical Rates* (New York, 1921), p. 37. The commissions that have given the most attention to rate-structure principles are the stronger commissions, such as those of California, New York, and Wisconsin, which have the aid of relatively large expert staffs.

A strong case can be made for the contention that, as far as feasible, fundamental problems of rate-structure revision should be handled in special proceedings, since they need far more time for satisfactory solution than can properly be given to them in what the Interstate Commerce Commission calls the "revenue cases." Referring to this situation in railroad rate cases, Professor Merrill J. Roberts writes: "The general rate case as presently construed is a veritable farce. Its broad sweep virtually precludes even the most rudimentary consideration of the intimate demand and cost relationships that should govern pricing in specific markets." "Maximum Freight Rate Regulation and Railroad Earnings Control," 35 *Land Economics* 125–138 at 136 (1959). See also footnote 11 of Chap. XVIII.

to the inability of the rate maker to predict the effect of changes in rates on demand for the services and hence on costs of supply—due, in short, to ignorance of demand functions and cost functions. But in part—and this is the most serious theoretical difficulty—it is due to the necessity, faced alike by public utility managements and by regulating agencies, of taking into account numerous conflicting standards of fairness and functional efficiency in the choice of a rate structure. The nature of some of these conflicts will be revealed as the discussion proceeds. But, by way of illustration, we may note the conflict between the desirable attribute of simplicity and the otherwise desirable attribute of close conformity to the principle of service at cost. Here, as with other clashes among various desiderata of rate-making policy, the wise choice must be that of wise compromise; and in reaching this compromise, the practical rate expert would look in vain to any general theory of public utility rates, at least in its present stage of development, for a scientific method of reaching the optimum solution.[2]

In view of this complexity of subject matter, the present study will not undertake descriptions of the typical rate structures of the different types of public utilities; and the reader unfamiliar with these structures is therefore referred to the treatises for background material, in the absence of which the following discussion of general principles may seem hopelessly abstract.[3] Even in its treatment

[2] Certain *approaches* toward a rational solution may be possible. Note, e.g., one economist's attempt to compare the additional costs of time-of-day metering as a device for differential electric rate making based on on-peak versus off-peak use with the possible resulting savings in plant generating capacity. Ralph Kirby Davidson, *Price Discrimination in Selling Gas and Electricity* (Baltimore, 1955), pp. 182–195. But other "intangible" costs of time-of-day metering are not readily assessed. In its investigation of the nationalized electric supply industry, a British inquiry commission concluded that, acting under statutory mandate to simplify rate structures, the Electricity Boards had deviated too far from the principle of rate differentials based on service at cost. *Report of the Committee of Inquiry into the Electricity Supply Industry*, Jan., 1956, Cmd. 9672, pp. 104–105. Needless to say, however, the Committee supplied no formula by which to draw the line between too much and too little simplicity.

[3] In addition to the treatment of rate structures in the general textbooks on public utility and transportation economics, see Caywood's book already cited in footnote 1; J. M. Bryant and R. R. Herrmann, *Elements of Utility Rate Determination* (New York, 1940); L. R. Nash, *Public Utility Rate Structures* (New York, 1933). For a significant critical monograph on modern utility rate structures in the United States, see Ralph Kirby Davidson's study already cited in footnote 2. On many technical issues, no American treatise on electric utility rates can equal that by the distinguished British rate engineer, D. J. Bolton, *Electrical Engineering Economics*, Vol. II: *Costs and Tariffs in Electricity Supply*, 2d ed. (London, 1951).

of principles, these chapters are mere essays on the nature of the more controversial, largely unresolved, problems rather than attempts at systematic development. All of them have one theme in common: the thesis that the most formidable obstacles to further progress in the theory of public utility rates are those raised by conflicting goals of rate-making policy.

CRITERIA OF A DESIRABLE RATE STRUCTURE

Throughout this study we have stressed the point that, while the ultimate purpose of rate theory is that of suggesting feasible *measures* of reasonable rates and rate relationships, an intelligent choice of these measures depends primarily on the accepted *objectives* of rate-making policy and secondarily on the need to minimize undesirable side effects of rates otherwise best designed to attain these objectives. No rational discussion, for example, of the relative merits of "cost of service" and "value of service" as measures of proper rates or rate relationships is possible without reference to the question what desirable results the rate maker hopes to secure, and what undesirable results he hopes to minimize, by a choice between or mixture of the two standards of measurement. Not only this: the very *meaning* to be attached to ambiguous, proposed measures such as those of "cost" or "value"—an ambiguity not completely removed by the addition of familiar adjuncts, such as "out-of-pocket" costs, or "marginal costs," or "average costs"—must be determined in the light of the purposes to be served by the public utility rates as instruments of economic policy. This is a commonplace; but it is a commonplace which, so far from being taken for granted, needs repeated emphasis.

What then, are the good attributes to be sought and the bad attributes to be avoided or minimized in the development of a sound rate structure? Many different answers have been suggested in the technical literature and in the reported opinions by courts and commissions; and a number of writers have summarized their answers in the form of a list of desirable attributes of a rate structure, comparable to the "canons of taxation" found in the treatises on public finance. The list that follows is fairly typical, although I have derived it from a variety of sources instead of relying on any

one presentation. The sequence of the eight items is not meant to suggest any order of relative importance.

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company:
   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).

Lists of this nature are useful in reminding the rate maker of considerations that might otherwise escape his attention, and also useful in suggesting one important reason why problems of practical rate design do not readily yield to "scientific" principles of optimum pricing. But they are unqualified to serve as a base on which to build these principles because of their ambiguities (how, for example, does one define "undue discrimination"?), their overlapping character, and their failure to offer any rules of priority in the event of a conflict. For such a base, we must start with a simpler and more fundamental classification of rate-making objectives.

THREE PRIMARY CRITERIA

General principles of public utility rates and rate differentials are necessarily based on simplified assumptions both as to the objectives of rate-making policy and as to the factual circumstances under which these objectives are sought to be attained. Attempts to make these stated principles subserve all special objectives and cover all specific conditions would be hopeless. Writers on the theory of rates are therefore at liberty to base their analyses on the acceptance of those objectives which are of wide application and the attainment of which may be aided by whatever tests or measures of sound rate structure the analyses suggest.

Among these objectives, three may be called primary, not only because of their widespread acceptance but also because most of the more detailed criteria are ancillary thereto. They are (a) the revenue-requirement or financial-need objective, which takes the form of a fair-return standard with respect to private utility companies; (b) the fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed *fairly* among the beneficiaries of the service; and (c) the optimum-use or consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received.[4]

In actual rate cases, these three criteria of reasonable rates and rate relationships, and particularly the last two, are by no means always sharply distinguished. But the distinction may be illustrated by the imagined example of a request, submitted to a regulating commission by a group of consumers, that an electric company be ordered forthwith to abandon its present, somewhat elaborate, schedule of class rates, block rates, and two-part or three-part

[4] These three criteria correspond to three of the four "primary functions" of utility rates set forth in Chap. III. The function ignored for present purposes, that of encouraging managerial efficiency, is omitted because of its more direct bearing on the desirable criteria for a fair over-all rate of return. See pp. 262 ff., *supra*. Professor John Maurice Clark had in mind essentially the same three criteria in writing: "The chief purposes of a rate system should be to earn a reasonable total return, to develop the utmost use of facilities so long as every service pays at least its differential cost, and to distribute residual costs fairly according to the responsibility of different users for the amount of these costs." *Studies in the Economics of Overhead Costs* (Chicago, 1923), p. 322. Professor Donald H. Wallace added a fourth possible objective: that of benefiting specific classes of customers, such as customers of substandard income or a submerged industry. Temporary National Economic Committee, Investigation of Concentration of Economic Power, 76th Congress, 3d Session, Monograph No. 32: *Economic Standards of Government Price Control* (Washington, D.C., 1941), pp. 475–478. This fourth objective comes under the heading of "social" principles of rate making as I have used the term in Chap. VII.

tariffs in favor of a uniform kilowatt-hour rate for all customers throughout its franchise territory. Almost certainly this proposal would be held subject to the threefold objection: (a) that no uniform rate, however high, could be made to yield a fair return on the company's invested capital; (b) that, even if it could do so, rate uniformity despite lack of cost uniformity in the supply of different types of service would impose *unfair* burdens on the consumers of the less costly services; and (c) that, quite aside from its unfairness, the uniform rate would result in a serious underutilization of plant capacity because it would cut down the demand for services (especially, for off-peak services) that could be supplied at increment costs materially below average unit costs, while stimulating a wasteful demand for services that can be supplied only at increment costs higher than the average.

Some modern writers who confine their attention to what they call the "economic" principles of public utility rates have ignored the second of these three standards of rate making in their development of these principles, on the ground that fairness questions are beyond the competence of professional economists.[5] Instead, they have centered attention on the third standard, often with special reference to its application under the constraint of a revenue-requirement standard. But a refusal to recognize fairness issues as relevant to the design of a sound rate structure would so far divorce theory from practice that these issues will not be completely ignored in the discussion that follows.

In the remainder of the present chapter as well as in all of the following chapters except Chapter XX ("The Philosophy of Marginal-Cost Pricing"), principles of rate structure will be discussed under the assumption that they are designed primarily to subserve the three above-noted objectives of rate-making policy. But in order to avoid extreme complexities, we shall make three further simplifying assumptions, all of which are implicit in much of the literature on public utility rates.

In the first place, we shall impute an unqualified priority to the "fair-return" standard of reasonable rate levels despite the fact, noted in Chapter IX, that no such priority is accorded either by legal doctrine or by rate-making practice. That is to say, we shall assume that the rates of any given utility enterprise, taken as a

[5] See Chaps. II and VIII.

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whole, must be designed as far as possible to cover costs as a whole including (or plus) a fair return on capital investment.

In the second place, we shall assume the availability of a wide range of alternative rate structures, any one of which could be made to yield the allowed fair return on whatever capital investment is required in order to supply the demand for service. This assumption, which implies that the utility enterprise in question enjoys a substantial degree of monopoly power, permits us to center attention on a choice among rate structures, any one of which would be equally fair to investors and equally effective in maintaining corporate credit.

And in the third place, except for incidental references, we shall rule out all of those so-called "social" principles of rate making, discussed in Chapter VII, which may justify the sale of some utility services at less than even marginal or out-of-pocket costs.

IMPORTANCE AND LIMITATIONS OF THE PRINCIPLE OF COST OF SERVICE

Without doubt the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service. In the literature, this measure is generally given a dominant position even by writers who insist upon, or reluctantly concede, the necessity for deviations from cost in the direction of value-of-service principles or of various "social" objectives of rate making. In actual practice there is usually an obvious, marked degree of correlation between the relative charges for different amounts and types of service and the relative costs of rendition. To be sure, local transit rates, with their customary flat fares regardless of distance and (even more important) regardless of time of travel come close to providing an outright exception. But intercity railroad rates, despite their many familiar departures from cost principles [6] and despite their notorious failure to accord well with any other sane principles of rate making, bear important partial correlations with

[6] Referring to railroad rates, the Interstate Commerce Commission said: "Costs alone do not determine the maximum limits of rates. Neither do they control the contours of rate scales or fix the relations between rates or between rate scales. Other factors along with costs must be considered and given due weight in these aspects of rate making." 262 I.C.C. 693, quoted by Justice Douglas in New York v. United States, 331 U.S. 284, 328 (1947).

relative costs. Thus, by and large, Pullman fares are much higher than coach fares; charges for the shipment of ten tons of any given class of freight are much higher than charges for the shipment of one ton; and freight rates from New York City to points in California are far higher than freight rates from New York City to Albany. Electric utility rates deviate from a cost standard much less than railroad rates. But it is a testimony to the prestige of this standard that, whenever actual or proposed electric tariffs are criticized for their asserted unfairness, the criticism usually takes the form of the contention that the rate relationships fail to conform to cost relationships. When this complaint is made before a public service commission, the defenders of the rates are likely to feel in a much stronger position if they can meet it on its own ground, without having to rely on value-of-service arguments in support of preferential rates to favored classes of customers.

The basic reasons in support of a cost-of-service standard of public utility rates and rate relationships have already been discussed at length in the early chapters of this book, particularly in Chapter IV. Here we may recall that the defense rests both on considerations of fairness as among the different customers and on considerations of optimum utilization or "consumer rationing." As to the issue of fairness, a cost-price standard probably enjoys more widespread acceptance than any other standard except for the even more popular tendency to identify whatever is fair with whatever is in one's self-interest. As to the issue of optimum utilization, this same standard (or, at least, a standard of the same name) comports with the "consumer sovereignty" principle, under which public utility consumers should be encouraged to take whatever types of service, in whatever amounts, they wish to take as long as they are made to indemnify the utility enterprise for the costs of rendition.

NECESSARY DEVIATIONS FROM A COST-OF-SERVICE STANDARD

In view of what has just been said, one might suppose that "the theory" of public utility rate structures or rate differentials would call for the acceptance of no basic principle of reasonable or nondiscriminatory rates other than a mere extension of the very principle already accepted in the determination of entire rate levels, namely, the principle of service at cost. Just as, under the fair-return standard, rates as a whole should cover costs as a whole, so the rates for any given class of service (passenger versus freight, residential versus commercial, etc.) should cover the costs of supplying that class, and so the rates charged to any single customer within that class should cover the costs of supplying this one customer. Under this assumption, the theory of rate structures would be reduced to a mere theory of cost determination through the aid of modern techniques of cost accounting and cost analysis.

Unfortunately, however, no such simple identification of "reasonable" rates with rates measured by costs of service is attainable; and this for several reasons, three of which will now be distinguished. The first of these reasons may be called "practical," whereas the other two are theoretical and are based on the nonadditive character of the costs attributable to specific classes and units of service.

Excessive complexity of cost relationships. The "practical" reasons lie in the extreme difficulties of cost-of-service measurement together with the fact that, even if all specific costs could be measured, they would be found too complex for incorporation in rate schedules. Most public utility companies supply many different kinds of service even when they confine their activities to nothing but electricity, or gas, or telephone service, etc. In a very real sense, moreover, the supply of any one type of service to thousands of customers at different locations constitutes the supply of a different product to each customer. Equally truly, service rendered at any one time is not the same product as is otherwise comparable service rendered at another time.

But these millions of different service deliveries by a single public utility company are produced in combination and at total costs, most of which are joint or common either to the entire business or else to some major branch of the business. Under these circumstances, the attempt to estimate what part of the total cost of operating a utility business constitutes the cost of serving each individual consumer or class of consumers would involve a hopelessly elaborate and expensive type of cost analysis.[7] For this reason alone, the most that can be hoped for is the development of techniques of cost allocation that reflect only the major, more stable, and more predictable cost relationships.

[7] John Alden Bliss has sent me a quotation from a report by Alex Dow, former chairman of the Detroit Edison Company, to the effect that his company had been obliged to reply on the one hand to the customer who thinks that rates should be uniform per kilowatt-hour and on the other hand to the man "who wants us to determine so exactly the cost of service to each customer that our power plants and distribution systems would become merely unavoidable preliminaries to the operation of a meter department." The TNEC Monograph No. 32, cited in footnote 4, *supra*, quotes at page 41 from an opinion by Chairman Maltbie of the New York Public Service Commission reading in part: "In every business, there is always a large percentage of customers, who are served at less than cost, for the reason that it has been found impracticable to devise and apply a system of cost accounting and computation which would carry out the principle literally; and if it were done, it would result in such an elaborate and complicated schedule of rates that the public could not understand it and few could apply it."

But even if, through the miracles of electronic computers and of modern techniques of mathematical analysis, all significant cost differentials could be measured without inordinate expense, they would then be found far too numerous, too complex, and too volatile to be embodied in rate differentials. Stability and predictability of the charges for public utility services are desirable attributes; and up to a certain point—or rather, up to an indeterminate point—they are worth attaining even at the sacrifice of nice attempts to bring rates into accord with current production costs. Indeed, unless rate-making policies are sufficiently stable to permit a consumer to predict with some confidence what his charges will be *if he decides* to equip his home or his factory to take the contemplated service and then to buy the service, a cost-price system of rate making will be self-defeating when viewed as a means of securing a rational control of demand.

These practical considerations leading to the design of rate structures that ignore many cost differentials are illustrated by the general uniformity of rates for gas, electricity, telephone service, and water supply throughout an entire city, despite distances from source of supply, differences in density of population, and other differences that may have a material bearing on relative costs of service. Indeed, in some parts of the country, the rates of large electric power systems are uniform, or almost uniform, throughout the state, no distinction being made between urban and rural areas. Critics of this "blanket rate" policy may well be right in insisting that it carries the principle of uniformity too far.[8] But the criticism is leveled merely against an *excessive* disregard of cost differentials in rate making.

Failure of the sum of differential costs to equate with total costs.

[8] See Chap. VII, pp. 112–113, *supra.*

We come now to a further limitation of the cost-of-service principle of rate structures—this one of critical concern when the rates must be made to yield a fair over-all return. It lies in the nonadditive character of the costs allocable, on a cost responsibility basis, to specific classes and quantities of utility service. In view of this failure of "the sum of the parts to equal the whole," the requirement that rates as a whole shall equal costs as a whole cannot be reconciled with a requirement that each consumer shall pay only the costs for which he, and no one else, is causally responsible; nor can it be reconciled with a requirement that each major class of consumers shall pay rates designed to cover the costs of serving that class, no more and no less. In consequence, save under circumstances that could occur only by rare coincidence, one of the two cost principles—the total-cost principle or the specific-cost principle—must give way. And, under the assumption of this chapter, the principle that must yield is that of service at cost as a measure of particular rates and rate relationships.

In stressing this probable conflict between the over-all-cost standard of entire rate levels and the specific-cost standard of the rate structure, the literature on rate theory has attributed it primarily to the distinction between average cost and incremental or marginal cost—a distinction familiar to the economic textbooks on the theory of price determination. This distinction will now be noted, although a second distinction will receive attention later. The point is that, when multiple products, or even multiple units of the same product, are produced jointly or in common, by an organically whole productive process, the only costs allocable solely to any given product or amount of product are *differential* costs. They are measured by a comparison between the total costs of the entire operation with the given output included, and the total costs with that output excluded.[9]

The most familiar and most significant form of a differential cost is incremental cost—the increment in total cost that will result from superimposing the production of the particular amount and type of product under inquiry on the other production. A special

[9] Under limited conditions, however, it is permissible to regard the net cost of one product, among a complex of jointly produced products, as measured by the total cost of producing the whole complex minus the proceeds of the sale of all the other products. These other products are then treated as by-products in the strictest sense of this term.

type of incremental cost, important for the theory of public utility rates, is marginal cost—a concept subject to various definitions but here best defined in a loose way, as the incremental cost, per unit, of producing a relatively small increment of a given product.[10] But these differential or incremental or marginal costs are nonadditive except under special conditions. For the determination of the cost of any particular type and amount of output assumes the continued production of the rest of the output, an assumption which is shifted when the costs of other types and amounts of output are under inquiry.

What has just been said as to the nonadditive nature of differential or incremental costs applies to all public utility companies which produce services of different kinds for many different people and in many different amounts. With an electric utility company, for example, the only cost specifically allocable to the residential service, *and not* to any other service, is the excess in total cost over what would be the cost of supplying all services other than residential. And the same statement would apply to an attempt to measure the cost that a company has actually incurred, or would incur in the future, in supplying a particular amount of service to any single consumer. The usual assumption is that, if the incremental costs of all services, separately measured, were added together, they would fall materially short of covering total costs—an assumption based on the belief that most public utility enterprises operate under conditions of decreasing costs with increasing output. When this assumption is valid, it implies that a public utility company cannot cover its total revenue requirements without charging *more* than incremental costs for at least some of its services.

The nonadditive character of the costs specifically allocable, on a cost-responsibility basis, to the different classes and amounts of public utility services has often been disguised by the acceptance of elaborate full-cost apportionments which begin with total costs and apportion these costs among the various classes of service as one might divide a pie among the members of a dinner party, leaving no residue for the kitchen. These "fully-distributed-cost" apportionments are especially familiar in the railroad field, where

[10] Marginal cost is sometimes defined as the increase in total cost resulting from the production of one additional unit of the product. But a one-unit margin is too narrow for most rate-making purposes.

they have been made under formulas developed by experts in the Interstate Commerce Commission. One such apportionment seems to indicate that the railroads of the United States, taken altogether, have been suffering annual losses of many millions of dollars per year on their passenger business. The usefulness of these apportionments is a debatable subject, which will be discussed in Chapter XVIII. But, in any case, their merits must rest on a claim that they represent, not a finding of the costs definitely occasioned by this class of service rather than that, but rather a *fair* or *equitable* division of total costs or else a statement of relative, not absolute costs. Even the cost analysts who make these full-cost apportionments recognize this fact implicitly when they concede, as they usually do, that a company may find it profitable to sell some classes of service at less than their imputed costs.[11]

The "cost" used as a measure of total revenue requirements is not the same kind of cost as the "cost" most clearly relevant to the design of the rate structure. The source of the previously discussed discrepancy between the total costs of an entire utility business and the sum of the costs causally allocable to the particular amounts and types of service lies in the distinction between *average total* costs and *incremental* or *marginal* costs. Whenever this discrepancy prevails, which it will do if the public utility company is operating under conditions of decreasing unit cost with increasing rates of output, rates set at incremental cost would tend to fall short of total costs. But we must now note another reason why the sum of the costs attributable to the specific services of a public utility company may fail to reflect the total costs of running the entire business.

[11] Public utility companies have sometimes invoked a marginal or incremental cost principle in defense of special rate concessions to very large customers, the defense resting on the contention that the revenues from this favored service will cover, or more than cover, all *additional* costs of its production. The weakness of this defense lies not, as sometimes asserted, in the invalidity of the incremental cost principle, but rather in a company's unsymmetrical proposal to base the preferential rate on incremental cost while basing the other rates on residual cost. Even this latter proposal may be justified in special cases; but the practice constitutes a form of rate discrimination, not a form of cost pricing. Its reasoning has been rejected as a defense against the charge of unlawful discrimination under the provisions of the Robinson-Patman Act. See Herbert F. Taggart, *Cost Justification*, Michigan Business Studies, Vol. 14, No. 3 (Ann Arbor, 1959), pp. 538–539: "The differential cost approach to cost justification is totally unacceptable. This means that a cost cannot be ignored *merely* because a given cost category would not be changed by the acquisition or loss of a certain customer or order or quantum of production." See also Frederick M. Rowe, "Cost Justification of Price Differentials under the Robinson-Patman Act," 59 *Columbia Law Review* 584–617 at 594 (1959).

This reason lies in the important distinction between historical or "sunk" costs and anticipated or "escapable" costs. A company's total revenue requirements, as measured under a fair-return standard, depend on liabilities and quasi liabilities for the payment of operating expenses and capital costs already partly predetermined by earlier transactions, including earlier purchases of plant, land, and other resources. On the other hand, the costs most clearly relevant to the determination of specific rates, at least under an optimum-utilization objective of rate-making policy, are those anticipated costs that can still be escaped or minimized by a control of output. This important distinction between the two types of cost is drawn most sharply when the revenue requirements are determined under an original-cost rule of rate making.[12] But the distinction remains, though in a blurred status, even under a so-called "fair-value" rule as actually applied by courts and commissions.

In short, then, there are two quite different sources of possible conflict between a cost-price system of reasonable rate levels and a cost-price system of specific rates and rate relationships. But, if the revenue requirements of the company are lower than would be the requirements of a new company, as they are likely to be during a period of rising construction costs and rising site values, the two sources of conflict may result in a partial offset. It is with this possibility in mind that some economists, who view with regret the necessity of charging public utility rates in excess of marginal costs, have tended to favor an original-cost type of rate base during a period of price inflation.

THREE WAYS BY WHICH TO RECONCILE THE COST-OF-SERVICE PRINCIPLE OF INDIVIDUAL RATES WITH THE MANDATE OF A FAIR OVER-ALL RETURN

For the reasons just suggested, rates based merely on specific or incremental or marginal costs might well suffice, on occasion, to yield adequate, or even more than adequate, total revenues under a fair-return standard. But the general principles of public utility rates dare not rely on such a convenient harmony. Instead, they

[12] See pp. 75–77, *supra*. In Chap. I of his *Economics of Sellers' Competition* (Baltimore, 1952), Professor Fritz Machlup stresses the impossibility of a rational allocation of the historical costs of standard accounting when the assumed objective is to determine the specific costs of producing any given product among a complex of products.

must apply to situations in which a public utility company, in order to cover its operating expenses plus a fair return, must charge more than incremental costs for much of its service—more, that is, than any costs definitely assignable to specific renditions of service on a cost-responsibility basis. In these situations, which are usually assumed to be typical of American railroads and public utilities, the problem then becomes that of devising rules of rate design under which there can take place a recovery of total revenue requirements without too severe disregard of principles of equitable cost apportionment, and with a minimum sacrifice of standards of optimum utilization of service.

Some of the modern literature of rate theory approaches this problem by treating a rate as composed of two parts: a minimum rate, called a "price," and a surcharge, called a "quasi tax." [13] Subject to important reservations, the "price" component should be set at marginal cost—at the specific cost that can be imputed on a causal basis to a relatively small increment of service. The surcharge, on the other hand, is a charge in excess of specific cost and is designed to yield an appropriate share of the unallocable total costs.

The significance attached to this somewhat artificial distinction between the price component and the surcharge component of a utility rate lies in the different functions performed by the two elements. In setting a minimum rate, the "price" is deliberately designed to create a barrier against wasteful or distorted use of the service in question. That is to say, up to this point any tendency of the rate to restrict consumption is deemed a desirable tendency. On the other hand, the surcharge is imposed merely for the sake of yielding necessary income to the company, and insofar as it also operates further to restrain the use of the service, this result is regarded as an undesirable side effect.[14] Hence, the problem faced by

[13] For example, Marcus Fleming, "Optimal Production with Fixed Profits," *Economica*, Aug., 1953, pp. 215–236. The conception of railroad rates as a form of tax insofar as they exceed out-of-pocket cost, and especially insofar as they are based on "value-of-service" considerations, has had a long tradition. Langdon recalls that the Interstate Commerce Commission expressed this point of view in its first Annual Report, 1 I.C.C. Rep. 31 (1887). Jervis Langdon, Jr., "Regulation of Competitive Business Forces: The Obstacle Race in Transportation," 41 *Cornell Law Quarterly* 57–92 at 86, note 165 (1955).

[14] This statement must be qualified in recognition of the requirement that if a surcharge is imposed on any one service, counterbalancing surcharges must also be imposed on alternative services in order to avoid distortionate substitutions. See Chap. XIX.

rate theory is that of suggesting rules for the determination of surcharges, over and above marginal costs, that will yield the required total revenue with the minimum of incidental harm in the form of curtailment of service otherwise worth rendering. But "minimum harm" cannot be identified with minimum curtailment of consumption in terms of physical intake such as kilowatt-hours, cubic feet of gas, or passenger miles. For, if the curtailment applies to service for which potential consumers would be willing to pay only slightly more than mere incremental costs of production, the loss of benefits is less serious than that resulting from equal curtailment of service which potential consumers would value at far more than marginal cost.

The problem of determining what surcharges will impose the least serious harm in the form of curtailments and distortions of use of service when the rates as a whole must yield total revenue requirements is perhaps the most complex and most difficult problem of modern rate theory. Not only does it require for its solution highly involved mathematical analysis; in addition, the application of this analysis depends on a knowledge of cost functions and of demand functions that practical rate makers simply do not and cannot possess. How far these refinements of theory may lend themselves to practical use in the future is a question on which I venture no opinion. But certain elementary aspects of the problem can be discussed without reference to the tools of mathematics; and they will be discussed in Chapter XIX, on rate discrimination.

Broadly speaking, if one assumes that ideal rates, viewed from the standpoint of the optimum use of service, would be rates set at marginal cost, there are three alternatives, or rather types of alternatives, by which one might seek to approach this optimum while imposing rates designed to meet total revenue requirements.[15] Under the first alternative, rates for different types of service would be made directly proportional to marginal cost, each rate exceeding the correlative marginal cost by the minimum fixed percentage necessary to cover total costs, say 20 per cent. Under the second

[15] A fourth alternative would be the apportionment of the burden of the cost residues, over and above marginal costs, by reference to some "social" principle of rate making in line with the fourth possible criterion of a sound rate structure mentioned by Professor Wallace in the article already cited in footnote 4. But the application of these social principles would not be consistent with the acceptance of marginal or out-of-pocket costs as setting the lower limits of utility rates.

alternative, rate differentials would be designed to cover cost differentials as between substitute classes of service. Under the third alternative, rates would be deliberately "biased" through the imposition of higher surcharges, relative to marginal costs, for those types and amounts of service for which the demand is relatively inelastic, and through the concession of lower surcharges (or even of relief from any surcharge) for types and amounts of service for which demand is relatively elastic. This last-named practice is an application of the familiar "value-of-the-service" principle of rate making, otherwise known as the principle of charging what the traffic (or what the market) will bear.

Before turning to another aspect of the problem of rate making raised by a failure of rates based on incremental or marginal costs to yield adequate total revenues, let me note that the "synthetic" approach just outlined, according to which the rates are conceived of as built up by the superimposition of appropriate surcharges on minimum rates set at marginal costs, is not in widespread use in actual rate making. Instead, the rates are more likely to be derived in part from apportioned total costs, with marginal or out-of-pocket costs serving only to set the lower limits below which no rates will be fixed under a value-of-service principle. The nature and significance of these fully apportioned costs will be discussed at length in Chapter XVIII.

AGGREGATE CLASS COST AS A RATE-MAKING STANDARD INTERMEDIATE BETWEEN TOTAL COST AND MARGINAL COST

In order to draw the distinction between total costs and specific costs in its sharpest form, we have so far contrasted these costs at their extreme ends. That is to say, we have identified total costs with a company's entire revenue requirements, whereas we have identified specific costs with the incremental costs of a very small output of service—marginal costs. But we must now consider the possible relevance for rate-making purposes of costs intermediate between grand-total costs on the one hand and marginal costs on the other. These intermediate costs are illustrated in the railway field by the distinction between the costs of passenger service and the costs of freight service, or by the distinction between the costs of the Eastern Division and the costs of the Western Division. In the electric power field, they are illustrated by the costs of supplying major classes of customers, such as domestic, commercial, industrial, street lighting, electric railway, and rural. Each of these major classes can be divided into numerous subclasses for purposes of cost analysis. But we may ignore this complication in raising the question whether public utility rates should be designed to make domestic consumers as a group pay for domestic-service costs as a whole, and so on through the entire list of service classes.

This is a controversial question, among other reasons because it raises the further question as to the relevant definition of group or class costs. Here economists and utility cost analysts are likely to differ. The analysts have tended to identify class costs with some "reasonably" or "fairly" apportioned share of the total costs; whereas most economists would define the cost of serving any one class of consumers in terms of differential costs. Thus, for a railroad company, the only costs which economists would consider allocable to the passenger business and not the freight business would be whatever costs the railroad would save by dropping this business or avoid by refraining from taking it on. So also, to an electric company, the only cost that can be assigned definitely and solely to the supply of the residential service is the cost of adding this service to the other services, or alternatively the saving in cost that would result from closing down the residential-service department while continuing to supply industrial power, street-lighting service, etc. These two types of differential costs may differ widely in amount; but we may accept incremental costs as the more significant type with respect to an expanding public utility business.

Having defined a class cost as an increment cost, albeit a cost of a very *large* increment, we now face the question whether this is a cost to be covered, as a minimum, by the revenues received from the sale of all services falling within this class. Consistency with the full-cost principle of entire rate levels (unless this principle is adhered to merely for reasons of financial necessity) requires an affirmative answer. That is to say, just as each individual consumer should pay rates at least sufficient to cover the costs allocable expressly to him, so also the domestic consumers as a group should pay rates at least sufficient to cover the incremental costs of supplying that group. Failure to meet this standard of intermediate-cost coverage would involve internal subsidies, contrary to the spirit of financial self-sufficiency.

MAJOR CRITERIA OF A SOUND RATE STRUCTURE ILLUSTRATED BY AN IMAGINARY EXAMPLE OF ELECTRIC-UTILITY RATE MAKING

Despite the early warning that the reader must look elsewhere for concrete examples of public utility rate structures, I have thought it worth while to close this chapter with an imaginary example of an electric-utility enterprise which starts business with a tariff of the simplest form and which faces the need to practice various forms of rate differentiation in pursuit of the objectives of rate-making policy already set forth. Steam generation of power is assumed. The example is grossly oversimplified, and instead of following the actual historical trends of American electric-rate design, it is deliberately tailored for illustrative purposes. In order to follow the simplifying assumption of a rigid, fair-return standard of entire rate levels, we shall suppose that the company, which might be a municipally owned "public corporation," is under a mandate to secure a 6 per cent rate of return on capital investment but seeks to attain this goal by a fair apportionment of total costs among the different consumers and by resort to rate differentials designed to encourage the optimum use of its service.

1. THE INITIAL TARIFF: UNIFORM RATE PER KILOWATT-HOUR

Commencing business at a time when electric supply has but little use other than for illumination, with the anticipated result that use of service will be fairly homogeneous, our company decides in favor of a completely uniform, single rate of charge. This rate, of course, must equal the average total cost of service, inclusive of the 6 per cent rate of return. But there remains a choice as to the unit of service to which the uniform rate shall be applied. Among a variety of alternatives, three receive closest consideration: a uniform charge per customer; a uniform charge per unit of energy (kilowatt-hour); and a uniform charge per unit of the customer's maximum monthly kilowatt demand.

Uniformity of charge per customer (say, $10 per month for any desired quantity of service) has charm in avoiding metering costs. Nevertheless, it is soon rejected because of its utter failure to

recognize either cost differences or value-of-service differences between large and small consumers. The choice between a uniform rate per kilowatt-hour and a uniform rate per kilowatt of maximum demand presents a nicer problem, especially so since the engineering consultants disagree as to whether the total costs of the business will vary more nearly with changes in output of energy or with changes in customers' maximum loads. But the decision is finally in favor of the kilowatt-hour charge, not so much for reasons of cost analysis as for reasons of the greater familiarity, and hence the greater public acceptability, of a charge based on amount of service in a popular sense of this term. There is the additional consideration that, if no charge whatever is made for off-peak consumption of energy, consumers will waste the service by carelessness in turning off their lights—a serious source of loss to the company since fuel costs in these early days of the industry are high because of the inefficiencies of available prime movers.

Accordingly, the company commences business with a rate of 20¢ per kilowatt-hour for any amounts of service to any consumers located within its franchise area. The 20¢ rate represents the estimated average total costs of electric service inclusive of the 6 per cent rate of return.

2. THE INTRODUCTION OF QUANTITY DISCOUNTS THROUGH RESORT TO A BLOCK-ENERGY RATE

By an amazingly good stroke of luck, the 20¢ rate per kilowatt-hour actually yields the estimated 6 per cent rate of return. But it obtains this yield in the face of serious deficiencies from the standpoint of the two other major objectives of rate-making policies. In the first place, in treating the total cost of the business as if it varied directly with changes in the kilowatt-hour output of energy —a grossly false assumption—it violates the most widely accepted canon of fair pricing, the principle of service at cost. In the second place, the uniform rate is so high relative to incremental costs that it discourages customers from increasing their consumption even though they would be ready to pay follow-on rates well in excess of incremental costs.

In order to meet these deficiencies, the company decides to introduce a practice familiar in the marketing of commodities at retail, the practice of quantity discounts. However, it departs from the traditional form of this practice by the use of block-energy rates.[16] For the first 25 kilowatt-hours of use per month, a consumer is charged 20¢ per kilowatt-hour as before. For the additional energy up to 50 kilowatt-hours per month he is charged 10¢ per kilowatt-hour. Finally, for all consumption in excess of 50 kilowatt-hours per month he is allowed a 5¢ rate. The lower rates for the second and third blocks are justified partly on cost grounds and partly on value-of-service considerations. As to the cost grounds, it is believed that an increase in consumption per customer will result in a less than proportionate increase in cost of service, chiefly because, within any presently contemplated limits of use, it will not require any expansion of the present capacity of the distribution system.

3. THE INTRODUCTION OF CLASS RATES: DISTINCTION BETWEEN INDUSTRIAL CONSUMERS AND RESIDENTIAL CONSUMERS

The change from a uniform rate per kilowatt-hour to a block rate which allows quantity discounts proves to be a material improvement in actual practice. By reducing its rates for increased consumption the company is able to earn its required 6 per cent rate of return even without any increase in charges to small customers. Despite this fact, the change leaves much to be desired. The chief deficiency of the new tariff lies in its failure materially to improve the company's system load factor. Even at the terminal block rate of 5¢ per kilowatt-hour, electricity is put to only limited use except for lighting. As a result, the company's expensive plant lies largely idle except for a few hours in the evening. What is needed, therefore, is some change in the tariff designed to encourage off-peak use of power. At the present time in the company's development, before the days of many tempting electrical appliances for household use, the most promising source of off-peak use lies in the industrial consumer, who may possibly be induced to stop using his own steam engine and, instead, to buy electric power during the daytime in order to drive his machinery.

[16] "This type of rate specifies certain prices per kilowatt-hour for various kilowatt-hour blocks, the price per kilowatt-hour decreasing for succeeding blocks." Caywood, *Electric Utility Rate Economics,* p. 43. The block-meter rate has almost completely superseded the step-meter rate, which applies to a customer's *entire* consumption of energy the same rate per kilowatt-hour decreasing with increases in consumption.

But the only hope of encouraging widespread industrial purchase lies in the concession of rates low enough to induce factories not only to use electric power but also to purchase this power from the company instead of producing it in their own generating plants.

In order to meet this situation, the company decides to split its service into two classes: residential and small commercial service (which we shall also call residential for convenience) and industrial power service. The residential rates are reduced 20 per cent so that they are now 16¢ for the first block, 8¢ for the second block and 4¢ for the third block. But the industrial power rates are still lower—let us say 4¢ per kilowatt-hour for monthly consumption up to 10,000 kilowatt-hours, 3¢ from 10,000 to 50,000 kilowatt-hours, and 2¢ for all consumption in excess of 50,000 kilowatt-hours. While, at least from a superficial standpoint, the grant of lower rates to power users may be said to constitute discrimination against the residential users, the discrimination—if so it may be called—will actually operate to the advantage of the residential users themselves since they will receive a rate reduction that could not otherwise be given them.

4. THE INTRODUCTION OF A TWO-PART RATE FOR INDUSTRIAL POWER: A DEMAND CHARGE AND AN ENERGY CHARGE

As already noted, the introduction of the low, industrial-power rate was designed to find useful, compensatory work for plant capacity that had been almost idle except during the evening hours. This objective, it was hoped, might be attained by the concession of below-average-cost rates to the one major group of customers that could be expected to use the service largely during the off-peak hours. To a material degree, moreover, these hopeful expectations have proved justified. The new industrial load has increased the system load factor from 15 to 25 per cent, so that an 85 per cent plant idleness has been reduced to a 75 per cent idleness, a striking improvement. Again, as in the shift from step two to step three, the change has been for the better.

But it is still far from good enough, especially so since the class-rate differentiation has one serious flaw: namely, in its identification of industrial use with off-peak use, and of residential use with on-peak use. True, in an early stage of electric-appliance history, the latter identification was not too far from reality. But much of the industrial-power use now overlaps the peak of the residential use, with the result that a material fraction of the industrial power has to be supplied at high, peak-time costs. Indeed, some industrial consumers confine most of their outside purchases of power to seasons and hours when the utility plant is operating close to full capacity, relying on their privately owned generating plants to produce their base-load power.

What is needed, therefore, is an industrial-power rate which makes a nicer distinction among different consumers than the mere distinction between larger and smaller consumers. For this purpose the company, taking its lead from a famous British electrical-utility engineer, Dr. John Hopkinson, introduces a two-part rate composed of an energy charge and a demand charge.[17] The demand charge for each industrial-power consumer is based on the maximum (30-minute period [18]) demand of this customer during the previous twelve months, as measured in terms of kilowatts (rather than kilowatt-hours) by a maximum-demand meter. For any one month, the customer's bill is made up of the sum of the energy charge and of the demand charge. As a result, the consumer with the higher load factor pays a lower charge per kilowatt-hour than the consumer of the same amount of energy at a lower load factor.

The full rationale of this Hopkinson, two-part rate is far from simple. But the rationale usually given (although it will serve only as a first approximation) is that the two-part rate distinguishes between the two most important cost functions of an electric-utility system: between those costs that vary with changes in the system's output of energy, and those costs that vary with plant capacity and hence with the maximum demands on the system (and subsystems) that the company must be prepared to meet in planning its construction program.

But, whatever its rationale from the standpoint of cost analysis, the introduction of the two-part industrial-power rate results in an improved use of existing plant capacity; and it gives such promise

[17] See Caywood, *Electric Utility Rate Economics*, pp. 48–50, 159.

[18] This period may vary from fifteen minutes to one hour or more. The use of a substantial period of time rather than a more nearly instantaneous period is said to have a twofold rationale: first, that electrical generation and distribution systems can stand heavy overloads for short periods; secondly, that the longer the period, the higher is the probability of coincidence between an individual customer's peak and the system or subsystem peak.

of increased power revenues, with only minor increases in the total costs of serving this class of business, that the company finds it feasible again to reduce its residential rates. The favorable effect of the demand charge on the power revenues is expected to result chiefly from three responses on the part of existing or potential power customers: first, from a tendency of existing customers to spread their loads over a longer period in order to minimize their demand charges, instead of bunching them during short periods likely to coincide with the heavy loads of other customers; secondly, from the deterrent effect of the demand charge on those industrial customers who, although operating their own private power plants, have hitherto relied on the company to carry their peak loads; and thirdly, from the fact that the two-part rate, which works to the advantage of a consumer with a high load factor, will offer the more favorable terms precisely to those consumers who are in the best position to resort to private generating plants if unsatisfied with the rates charged by the central station.

To be sure, the Hopkinson two-part rate, in the form here envisaged, is subject to one serious criticism in making the demand charge depend on the maximum demand of the individual customer at any time of day or season, rather than on his demand at the time of the system or distribution peak. But as to this objection, discussion will be reserved for Chapter XVIII.

5. THE INTRODUCTION OF AN OVERT OR CONCEALED THREE-PART RATE: CUSTOMER CHARGE, ENERGY CHARGE, AND DEMAND CHARGE

As already noted, the two-part Hopkinson rate is based on the assumption that one part of the total costs of an electric-utility business is a function of the output of energy of the system whereas another part is a function of plant capacity and hence of all costs related to this capacity. But this twofold distinction overlooks the fact that a material part of the operating and capital costs of utility business is more directly and more closely related to the number of customers than to energy consumption on the one hand or maximum kilowatt demand on the other hand. The most obvious examples of these so-called customer costs are the expenses associated with metering and billing. For residential customers these latter expenses may amount to $1 a month per customer. For industrial power users, the metering and billing expenses may be much higher. In addition, moreover, each industrial power user is likely to have expensive transformer and switching equipment devoted exclusively to his use. The capital costs and maintenance costs of such equipment are properly included as a customer cost (or, perhaps more accurately, as an individual demand cost rather than a system demand cost), in that they reflect a cost imposed by the individual customer even if and when he consumes no power whatever.

Having in mind these customer costs, our company decides to make a more or less direct allowance for them in its rates for charge of service. As to its residential rate, it first contemplates a customer charge of $1 per month, which would be added to the kilowatt-hour charge as a part of the monthly bill. However, this proposal meets with such opposition on the part of customers, who contend (erroneously but bitterly) that it is an attempt to charge them "something for nothing," that the company modifies its plan by introducing a $1.50 minimum monthly bill. Unlike the overt customer charge, this minimum bill permits the customer to consume up to 10 kilowatt-hours of energy without further payment. From the standpoint of cost analysis, it is decidedly inferior to an unqualified customer charge. But this inferiority is held to be outweighed by its greater palatability from the standpoint of the public taste.[19]

As to the industrial power rate, the unpopularity of an outright customer charge is not so serious, since power customers are sophisticated purchasers of electric energy. Nevertheless, even here the charge is incorporated in a minimum demand charge. The introduction of the (concealed) customer charge is significant chiefly for the residential consumer. Here it reduces the number of consumers who, because of their small use of energy, impose an out-of-pocket loss on the company.

The additional revenues derived from the minimum charge,

[19] See Hubert F. Havlik, *Service Charges in Gas and Electric Rates* (New York, 1938). In considering the proposed elimination of a service charge in the nature of a customer charge, the Missouri Commission said: "It is puerile for our commission to enter into the many scientific principles of rate making which support the service charge when the supporting public is unable or refuses to comprehend its scientific structure. Its continuance is and will continue to result in injury to the business of defendant." Stanley v. Harvey Elec. Lt. & Pr. Co., PUR 1921 E, 681. But a commission has some responsibility toward the education of the public in a matter of this kind.

combined with the saving in expenses resulting from the abandonment of service by those unprofitable consumers who decline to pay this charge, makes possible a reduction in the block-energy rates. The company decides to apply this reduction entirely to the tail-end block in order to promote the use of electricity by residential consumers. While the resulting rate for energy in excess of 50 kilowatt-hours per month is well below the average rate for residential consumption, it is justified on economic grounds in that it at least covers incremental costs, so that the residential consumer of large amounts of service is not enjoying an overt subsidy. The low terminal rate is further justified by the probability that the residential consumer who uses unusually large amounts of electricity will be using most of the excess for nonlighting equipment operated at off-peak hours. Unfortunately, this assumption that the larger use means a higher degree of off-peak use will be belied in many individual cases—especially so because the amount of use depends indirectly in part on the size of the consumer's residence. But the company, after considering an allowance for this size-of-house variable, perhaps by resort to a fixed monthly charge based on number of rooms, decides against the proposal—partly in view of its obvious theoretical infirmities and partly in view of its unpopularity.[20]

6. DIFFERENTIAL RATES FOR INDUSTRIAL POWER BASED ON VOLTAGE DIFFERENCES

The last revision in rate design to be introduced in this imaginary illustration takes the form of a rate differential to industrial consumers based upon differences in voltage at which they will accept alternating-current power from the electric company's transmission or distribution system. For reasons of economy, the company must transport its power from its central stations at high voltages, which must be stepped down to safe and workable voltages at or near the customer's premises. But it is feasible to grant to industrial consumers several options as to the voltage at which they shall receive the power from the company's substations or transformers. Hence, if a given industrial consumer is willing to accept the power at high voltage, he is properly given a discount

[20] Aside from the poor correlation between any index of *presumptive* customer load and actual load, such an allowance would fail to motivate a consumer to keep down his actual peak. G. P. Watkins, *Electrical Rates* (New York, 1921), pp. 58–64.

in his demand charges, or in his energy charge, or both, the amount of which should be designed to pass on to him the cost saving which he confers upon the company. With this object in mind and in view of the layout of its transmission and distribution system, the company offers to its industrial consumers an option of three voltages, which we may call "high," "low," and "medium." The company's basic rate (both in the form of demand charges and of energy charges) is the rate for low-voltage consumption. Its rates for medium-voltage and high-voltage consumption are derived from this basic rate with the object of coming as close as feasible to the principle of "rate differentials equal to cost differentials."

COMMENTS ON THE RATE STRUCTURE SUGGESTED ABOVE

The preceding paragraphs have suggested only a few of the many forms of rate differentiation practiced by modern electric utility enterprises, whether privately or publicly owned. They are designed to illustrate five important types of rate differentiation: namely, quantity discounts through block rates; class rates; two-part rates; three-part rates; and rates for alternative types of service related in such a way as to make the differences in charges equal the differences in costs of rendition. Our illustration ignores the fact that the classes of service, instead of being limited to two, are likely to be as many as ten or more; that a company may offer special rates for completely off-peak service including off-peak residential water-heating service; that industrial power is sold subject to many detailed terms including terms which make allowance for differences in the power factor; [21] and that special charges may be imposed by which to reimburse a company for the construction or installation of expensive equipment needed only to serve a specific user of the service.

Nevertheless, even as it stands in this oversimplified form, our illustration suggests the complex nature of the problem of rate design when this problem is envisaged as that of securing revenues which will yield a fair return by means of rate differentials that will not only fairly apportion total costs among the different con-

[21] Caywood, *Electric Utility Rate Economics*, pp. 59–66. Bolton, *Costs and Tariffs in Electricity Supply*, devotes Part IV of his book to this elusive factor in alternating-current electric supply and to forms of tariffs designed to penalize industrial users for power factors that are costly to the supplier, chiefly in compelling it to maintain excess capacity.

sumers, but will also secure the optimum amount of use of each type of service and of all the services taken in the aggregate. Seeking the closest feasible approach to the accomplishment of these three partly conflicting objectives, the rate maker has at his command a wide variety of schemes of differential rate making which he must apply, not singly but in combination. The choice of the best combination is unavoidably in the nature of a compromise, since the particular combination that he chooses is bound to be worse in some respects than many of the combinations which he rejects.

In the United States, for example, most companies, whether of their own volition or through coercion by regulating commissions, impose no maximum-demand charge on residential consumers. Moreover, they usually impose no customer charge except in the concealed and distorted form of a small minimum monthly charge. This rejection of overt multipart rate making as applied to residential use has pretty well restricted residential rate differentiations to the device of the quantity discount in the form of a block-energy rate—a very crude device when judged either from a cost standpoint or a value-of-service standpoint.

With all their deficiencies, the rate design typical of the American electric utilities is probably superior to that of any other regulated business in this country.[22] Along with improved engineering technology and with the development and promotion of electrical

[22] The superiority of so-called public utility principles of rate making, specifically of electric rate making, over traditional railroad-tariff principles was recognized many years ago by Professor John Maurice Clark in an article quoting a statement by Henry L. Doherty, a leading gas-company executive, that "Perhaps no other one factor has contributed so much to the success of the electrical business as the study of the rate problem." Clark, "Rates for Public Utilities," 1 *American Economic Review* 473–487 (1911). In recent years, and under the pressure of competing forms of transportation, this superiority has been recognized by the more progressive railroad executives. Thus, John W. Barriger, Jr., now President of the Pittsburgh and Lake Erie Railroad, insists that the railroads must "price their products to attract mass utilization of their facilities. The electric utilities are the outstanding example of the public and social benefits—as well as the economic and financial soundness—of such pricing." *Super-Railroads for a Dynamic American Economy* (New York, 1956), p. vi.

The primary claim for the superiority of electric-rate principles lies in their far less sweeping resort to "value-of-service" considerations, combined with their more thoroughgoing recognition of multiple cost functions as typified by the distinctions between customer costs, energy costs, and capacity costs. Because railroad tariffs are based so largely on a uniform rate per ton or per hundred pounds for any given commodity and any given movement, with few distinctions for volume except the extremely crude distinction between carload and less-than-carload rates, appliances, it shares the credit for the amazing success of the industry in reducing rates or keeping them from rising materially during a prolonged period of price inflation. But it is far from ideal, and practical rate makers will do well to consider seriously its alleged infirmities viewed from the standpoint of its critics among the academic economists.

Two of these alleged infirmities, which are really tied together, are, first, the allowance of quantity discounts said to be greatly in excess of any discounts defensible on cost-of-service principles, and secondly, the imposition of demand charges which penalize consumers for high individual demands even though these demands come at hours or seasons that fall well off the peak loads imposed on the system as a whole or even on any major part thereof. More will be said on these points in Chapter XVIII.

shippers are under no inducement to cooperate with railroads in loading cars to their full capacity, not to mention their lack of inducement to supply full-trainload lots. Major credit is due to Mr. John Alden Bliss, a transportation economist, for calling attention to the superiority of utility-rate design over railroad-rate design. See, e.g., "The Picture Is So Different with a Two-Dimensional Price," *The Analysts Journal*, Aug., 1954, pp. 89–95; "Maybe the Utilities Have Got Something in the Way They Make Rates," *Railway Age*, Aug. 18, 1952; "A Model of Make-or-Buy Competition," Contributed Paper (F2) for the Third Annual Meeting of the Operations Research Society of America, June 3 and 4, 1955; "A Short Survey of Non-Linear Pricing Forms," Contributed Paper (D5) for the Eighth National Meeting of the same society, Jan. 9 and 10, 1956; "Some Comments on Tobacco—North Carolina Points to Southern Points (Rail)," *I.C.C. Practitioners' Journal*, Dec. 1951, pp. 281–301.

XVII

MARGINAL COSTS, SHORT-RUN AND LONG-RUN

For reasons already indicated in the preceding chapter, the marginal costs of public utility services, as distinct from average total costs, are of such significance for sound rate determination that some economists have gone so far as to propose their acceptance as measures of rates even when, in consequence, the resulting revenues will fail to cover total costs and must therefore be supplemented by a tax-financed subsidy. The merits of this unorthodox proposal will be discussed briefly in Chapter XX, the last chapter.[1]

But even under the traditional principle that "rates as a whole should cover costs as a whole," marginal cost, or one of its approximate synonyms such as incremental cost or out-of-pocket cost,[2] plays an important role in the design of the rate structure.

[1] In a more logical sequence, Chap. XX, on unqualified marginal-cost pricing, would come first and would then serve as a basis on which to discuss the more complicated and confusing role to be played by marginal cost as a measure of *minimum* rates and as a factor in the determination of rate relationships subject to the requirement that rates as a whole must cover costs as a whole. Somewhat reluctantly, however, I have reversed this procedure in view of the unfamiliarity of marginal-cost pricing philosophy to persons other than academic economists. Incidentally, the relative simplicity of the theory of strict marginal-cost pricing as compared to the theory of "optimum pricing subject to a budgetary constraint" is a spurious simplicity, which the price theorist gains by wishing some of his most embarrassing problems upon the tax theorist!

[2] "Out-of-pocket cost," itself an ambiguous term, is the popular partial equivalent of "marginal cost," especially in railroad parlance. But it is sometimes used to refer merely to the additional *cash* outlay imposed directly by the production of additional output, whereas "marginal cost" also includes any enhancements in noncash costs (such as depreciation due to wear and tear of equipment) attributable to an increase in rate of output. An important study by Professors Wilson and Rose concludes that the Interstate Commerce Commission has in practice (though not often in language) identified "out-of-pocket" cost with average variable cost regardless of the question whether this latter cost remains constant or increases

In fact, it may play a dual role: first, in setting a lower limit below which no rates will be fixed, not even in order to promote the use of service which could not otherwise find a buyer; and secondly, in serving as a basis for relative rates, subject to deviations of a value-of-service nature.

More will be said of these two uses of marginal-cost estimates in the two following chapters. But in the present chapter we must take account of the fact that "marginal cost" is itself a highly ambiguous term, with the result that proposals to base minimum rates or rate relationships on marginal costs mean different things to different people. The most important ambiguity is that suggested by the distinction between "short-run" and "long-run" marginal costs. Indeed, this distinction is of critical import, for most of the really spectacular differences between incremental and average costs of public utility services are those which apply only when the former costs are taken to be of a short-run variety.

The first section of this chapter, which follows immediately, will therefore discuss the distinctions between the two types of marginal cost. Most of these distinctions would apply, with modifications, to short-run versus long-run incremental costs in general and not alone to costs of increments so small that they are called "marginal." The second section will then turn to the relative merits of short-run and long-run marginal costs as a basis of minimum rates. Here it will be noted that, in most public utility cost analyses, major importance has been attached to the longer-term version.

DISTINCTION BETWEEN SHORT-RUN AND LONG-RUN MARGINAL COSTS

GENERAL NATURE OF THE DISTINCTION

In its general sense, the "marginal cost" of a given commodity or service refers to the increase in total cost of production imposed by a relatively small ("marginal") increase in rate of output.

with an increase in the volume of traffic. In consequence, the Commission may well have accepted estimates of out-of-pocket costs, when offered in support of special reduced rates designed to meet competition, that were lower than marginal costs. G. Lloyd Wilson and J. R. Rose, "'Out-of-pocket' Cost in Railroad Freight Rates," 60 *Quarterly Journal of Economics* 546–560 (1946). One may surmise that awareness of this likelihood partly accounts for the Commission's traditional reluctance to allow railroads to quote competitive rates only slightly above calculated out-of-pocket costs.

Usually this increase is expressed in terms of an incremental cost per unit of increased output. Thus the marginal cost of producing electric energy may be 1¢ per kilowatt-hour, whereas the average cost may be 2¢.

But the amount of the marginal cost, and its relationship to average cost, will depend on many factors, one of which is that of the assumed duration of the enhanced rate of output. To an electric company, for example, the additional unit cost of a 5 per cent increase in its output of energy may be one figure if the enhancement in output is to last five minutes, another figure if it is to continue for five months, and still another figure if it is to be maintained for five years.

Any number of time-duration distinctions may therefore affect an estimate of the marginal costs of a specific kind of utility service. But by a convenient though partly arbitrary convention, economists have applied the words "short-run" or "short-term" to marginal costs estimated under the assumption that the enhanced rate of output will be temporary and will hence be accomplished solely by an increase in the rate of utilization of the existing plant and equipment; whereas they have applied the words "long-run" or "long-term" to marginal costs estimated under the assumption that the enhancement in rate of output will continue indefinitely and hence will be accomplished by an appropriate increase and adaptation of plant capacity.[3] Shortness of time is associated with absence of change in plant and (heavy) equipment partly because a sudden, unanticipated demand for an increased output can be satisfied, if at all, only by a more intensive utilization of the present plant, and partly because a demand for a merely temporary increase in output, even if it could be anticipated long in advance of its occurrence, would not be likely to warrant a plant expansion.

[3] This distinction is drawn in nearly all textbooks on economic analysis and is portrayed by geometric curves of the type developed by Jacob Viner in his celebrated article on "Cost Curves and Supply Curves," 3 *Zeitschrift für Nationalökonomie* 23–46 (1931), reprinted in George J. Stigler and Kenneth E. Boulding, eds., *Readings in Price Theory* (Chicago, 1952). For an excellent short exposition, see George J. Stigler, *The Theory of Price*, rev. ed. (New York, 1952), Chaps. 6 to 10; also *The Theory of Marginal Cost and Electric Rates*, an 80-page brochure on European rate making published by the Organization for European Economic Cooperation (Paris, 1958).

CHARACTERISTICS OF SHORT-RUN MARGINAL COSTS

Exclusion of "constant" or "fixed" costs. Reserving a closer analysis of long-run marginal costs for later paragraphs, let us first note the special characteristics of the short-run version. The most outstanding characteristic lies in the vital distinction drawn here between constant costs and variable costs. In short-run analysis the capital costs of plant and equipment are treated as constant and hence are excluded for the purpose of the estimate. Indeed, even a large share of the costs which accountants call operating expenses is treated in the same way, on the ground that many of these costs do not vary, at least not materially, with changes in the rate of plant utilization. This exclusion of a good part even of the operating costs applies notably to a portion, usually the major portion, of the operating-expense deduction for annual depreciation (in reality a capital cost), since only a minor part of this depreciation is deemed to be affected by the degree of use made of the equipment.

It is primarily because of these exclusions of large shares of the total costs of supplying utility service from estimates of short-run marginal costs that the latter costs are often found to constitute mere fractions of average total costs. Thus, if an electric utility company is now operating with a plant of excessive capacity, a substantial increase in rate of output of energy may impose almost no additional cost except for an increase in cost of fuel—an increase of, say, ¼ to ½¢ per kilowatt-hour as compared to average total cost of perhaps 2½¢. Indeed, if the supply of power comes from a hydroelectric plant of redundant capacity and with no opportunity to store the water for future use, the short-run marginal cost of the power may be practically zero. Leaving the plant idle and letting the water run over the spillway would result in almost no saving whatsoever.

Relationship between short-run and long-run marginal costs depends upon the current relationship between rate of output and plant capacity. Because short-run marginal costs exclude many components of total costs on the ground that, for the purposes of the analysis, these components must be deemed constant, one might assume that the former costs would always be relatively low—lower than either long-run marginal costs or average total costs.

Indeed, this assumption is implicit in some of the American treatment of railroad and utility rate making, which refers to "mere" incremental or out-of-pocket or marginal costs as if they were invariably lower than "fully allocated" costs. But no such assumption would be justified. For short-run marginal costs may be lower than, equal to, or higher than long-run marginal costs. And the same statement would apply to a comparison with average total costs.

In the economic theory of price determination, it is a basic principle that, when a plant is of the optimum size for the rate of output which it is called upon to deliver (that is, when the size of the plant is such as to minimize the total cost of continuous production at this rate of output), short-run and long-run marginal costs will coincide.[4] At this optimum size, the additional cost of producing a small enhancement in rate of output by a slightly greater utilization of the present plant will be just equal to the additional cost of producing this same enhancement with the aid of an increase in plant capacity. The increase in capital costs in the latter case would be precisely offset by the greater increase in the operating costs in the former case.

But if an existing plant is put under a strain to produce services beyond the rate of output for which it is well adapted, the resulting disproportionate increase in the variable operating costs may *more* than offset the fixity of the capital costs; and short-run marginal costs, even though still devoid of any capital costs, may nevertheless exceed long-run marginal costs.

With an electric utility plant, three developments in combination are likely to be largely responsible for this tendency of the variable costs sooner or later to increase much more than in proportion to the increase in rate of output. In the first place, the enhanced output must be supplied by those less efficient, obsolescent turbogenerators that would otherwise be kept in stand-by reserve. Fuel cost per kilowatt-hour will therefore increase. In the second place, stand-by reserve will be reduced to and past the danger point—a situation giving rise to an economic cost, although this cost,

[4] This is not to say that, for any desired rate of output, the plant of most economical size is necessarily a plant operating at its minimum unit cost at this rate of output. For, "when a firm is operating subject to, say, economies of scale, it is most economical to build a plant whose minimum cost comes at an output larger than is desired and to operate it at less than this minimum cost output." Stigler, *The Theory of Price*, p. 141. For practical illustrations, see D. J. Bolton, *Electrical Engineering Economics*, Vol. I, 3d ed. (London, 1950), especially Appendix III.

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when estimated in advance, must be expressed in probabilistic terms and may never get into the records of the company's accountants. And in the third place, the quality of the service is likely to deteriorate through voltage drops—another economic cost, though one of an intangible nature, which may be partly imposed on the company in the form of impaired good will and impaired standing with a public service commission. But only the first of these three elements of the short-run marginal costs of service produced by an overworked plant can usually be expressed in terms of mills or cents per kilowatt-hour. Hence, a statistical or accounting study of the behavior of operating costs of a given plant in response to changes in rates of output is almost certain to ignore important tendencies toward disproportionate increases in these costs as output approaches the upper physical limits of plant capacity.[5]

From what has been said it follows that the familiar phenomenon of extremely low short-run marginal or incremental costs—low in relationship both to long-run marginal costs and to average total costs—is a phenomenon of redundant plant capacity.

Meaning of short-run marginal costs when a plant is operating at the upper limit of its capacity. Public utility plants are not often called upon to produce services up to the very limits of their physical capacity. As a rule, advance provisions will have been made to increase plant capacity before the growth in consumption of service has encroached too seriously on emergency reserves. But let us suppose that the upper limit has indeed been reached and that any further increase in the rate of output of service would be either literally impossible or else utterly out of the question for reasons of safety. Under this assumption, what is the current, short-run marginal cost of utility service?

[5] "In the continued attempt to minimize load shedding up to and over its maximum safe capacity, risks of widespread failures of supplies had unavoidably to be taken." British Electricity Authority, *Third Report and Accounts* (1950–1951), p. 9. What has just been said may be a partial explanation of the results of a number of empirical studies, notably those by Professor Joel Dean, which tend to show a horizontal (constant) short-run marginal cost curve for a given plant throughout any actually experienced range in the rate of output. Another reason for the observed horizontality may be the paucity of data on the operating costs of plants that were being pushed close to the upper limits of their capacity. See Joel Dean, *Managerial Economics* (New York, 1951), Chap. 5. Compare J. Johnston, *Statistical Cost Analysis* (New York, 1960), section on electricity generation, pp. 44–73.

Here, if "marginal cost" is given its usual meaning, as referring to the marginal cost incurred by a company in *producing* the service, the question just raised is meaningless; for no increase in output is feasible at *any* additional cost. But, for purposes of rate making, an alternative concept and measure of marginal costs may now take the place of marginal production costs: namely, the marginal social cost necessarily involved when the supply of any amount of the scarce service to those consumers to whom the service is rendered means the denial of this same amount of service to those potential consumers who are thereby excluded.[6] Under familiar assumptions of resource allocation, this cost would be measured by the "market-clearing" price for the scarce service —by the price, say 10¢ or even $1 per kilowatt-hour for electricity, that would just suffice to bring demand into equality with potential supply. While such a price would not reflect marginal cost of production to the utility company, it would approximately measure "marginal exclusion cost" and hence would have much the same claim for acceptance, as a measure of rates, that short-run marginal cost of the ordinary variety would have with respect to a plant operated at less than maximum possible load.

Volatility of short-run marginal costs. In view of the above-noted characteristics of short-run marginal costs, it should hardly be necessary to add that these costs are typically of a highly volatile nature. Let the current rate of output be even slightly below the maximum output permitted by plant capacity (after an adequate allowance for emergency reserve), and marginal cost of service may be a mere fraction of average cost. But let the output increase to a rate only slightly in excess of that for which existing capacity is safely adequate, and marginal cost may jump to some multiple of average costs and to another multiple of long-run marginal costs. As will be noted in the second section of the present chapter, it is this volatility which most seriously impairs the usefulness of short-run marginal or incremental costs as measures of minimum rates or as a basis of sound rate differentiation.

[6] See William Vickrey, "Some Objections to Marginal-Cost Pricing," 56 *Journal of Political Economy* 218–238 at 231 (1948).

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CHARACTERISTICS OF LONG-RUN MARGINAL COSTS

Indefiniteness of the term except when strictly defined. As already noted, what distinguishes long-run from short-run marginal cost is that the former cost is measured under the assumption of a *sustained* increment in the rate of output—sustained for a period sufficiently long to require, or at least to justify, a change in the capacity and design of the plant and equipment. This means that those capital and operating costs which are treated as constant, and hence are excluded, in short-run cost analysis, are here treated as variable.

But unless the term is restricted to what may be called the "limiting case," it cannot be distinguished *sharply* from short-run marginal cost. For, at the current rate of output, the present plant may have an excess capacity with respect to *some* of its component parts while having no more than an adequate capacity with respect to others. Thus, an electric company might find it economical to supply for the next several years a 10 per cent increase in its output of energy by means of a 10 per cent increase in the capacity of its turbogenerators but with no enlargement whatever of its distribution network. Or a railroad might sustain indefinitely a 10 per cent increase in its freight traffic by a corresponding increase in rolling stock, together with a minor enlargement and improvement of its classification yards, but with no enhancement in its line-haul capacity. To make things even more complicated, one must recognize the likelihood that a given increase in rate of output might feasibly be supplied at first by very minor adaptations in plant and equipment, to be followed by major adaptations in later periods—perhaps after much of the older equipment is in urgent need of replacement.

Aware of this lack of sharpness in the distinction between short-run and long-run cost functions, economists have sometimes sought to give greater precision to the term "long-run marginal cost" by making it refer to those cost increments which would result from a shift from an indefinitely continuous rate of output accomplished by means of a plant of optimum design and capacity for that rate, to an indefinitely continuous higher rate of output to be accomplished by means of a plant of optimum design and capacity for this higher rate. This definition premises a "run" so extremely

long that the plant management has the opportunity to carry out all of those adaptations to the changed rate of output which would be economical under a given technology and under a given set of prices for the various "factors of production." [7]

But useful as is this tighter, "limiting-case" definition of long-run marginal cost for purposes of price theory, its acceptance would severely reduce its usefulness as a tool of practical rate making. For, in actual practice, the more significant marginal costs are those costs which can be expected to persist, not forever or even for twenty years, but rather for those shorter periods that are within the horizon of today's rate makers. As a rule, these are the increments in costs that may be anticipated to result, during the next several years, from increases in rates of output to be accomplished by whatever plant additions and improvements will be warranted in view of the actual layout and actual capacity of the present plant. There would be little point, for example, in basing today's railroad passenger rates on the long-run marginal or incremental costs of passenger service if these costs were to be estimated without recognition that an increase in this service may require little or no increase in right of way or in trackage for a long time to come, if ever. For, with most American railroads, partial plant redundancy is not just temporary but chronic, perhaps permanent.

The upshot of these comments on the indefinite meaning of long-run marginal cost is that, when used as a practical standard of rate making, the concept should be defined only in general terms and should be left for whatever nicer definition may be required in the light of the particular rate-making problem. Applied, for example, to a rapidly expanding utility enterprise such as a modern electric or telephone utility, long-run marginal cost may properly be associated more closely with its stricter definition than would be warranted with respect to a declining or slowly growing business, such as that of a railroad.

Qualification of the principle that all costs are deemed variable. We have already noted that a special characteristic of short-run

[7] Thus long-run marginal cost, strictly defined, is a concept of a stationary state. But Professor John Maurice Clark doubts whether, even if the process of change were to be stopped in such an imaginary state, there could be a return of capital to the point that it would reach if starting anew. "Some forms of capital cannot be shifted without loss, no matter how much time is allowed for the piecemeal transfer of the depreciation fund; a railroad embankment, for instance, or a tunnel." *Preface to Social Economics* (New York, 1936), p. 280.

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marginal cost determination lies in its distinction between "constant" and "variable costs" and in its complete exclusion of the former costs as components of marginal cost. This statement may seem to imply that, in long-run cost analysis on the other hand, all costs, including all capital costs, should be deemed variable, so that the whole distinction between constant and variable costs should disappear.

Properly interpreted, the above-suggested inference is correct. But the inference must be qualified, since it appears to be belied by the frequent practice of cost analysts in distinguishing between constant and variable costs in their estimates even of long-run incremental or marginal costs.

The first qualification is that the variability of *all* costs is not necessarily assumed except in that *very* long-run marginal-cost determination in which there is time for the *complete* adaptation of plant and equipment to any change in rate of output. If this extreme definition of a long-run marginal cost is not accepted, and if the objective is to estimate the increments in cost, say, that a given railroad would incur during the next five years if it were to enjoy a 5 per cent increase in its volume of traffic during this period, the assumption that some important items of cost will remain almost unaffected by the increment in traffic—say, the costs of the land for right of way—may be quite plausible.

The second qualification, although often not clearly distinguished from the first, is of a different nature. It is called for in recognition of the practice by some cost analysts of treating a given portion of the total costs *as if* it were constant and of treating the remaining portion *as if* its variability with rate of output were of a linear character. This artificial distinction between so-called constant costs and so-called (proportionately) variable costs may permit approximations of nonlinear cost functions in linear terms.[8]

Perhaps the leading examples of this practice are those used in railroad cost analysis. Thus, the Cost Section of the staff of the

[8] See p. 348, *infra*. This technique is illustrated by D. J. Bolton with reference to the relationship between the capital cost and the KVA capacity of a transformer substation. He adds: "The first step, therefore, in simplifying the cost relationship will usually be to express the cost as the sum of two components, one of which is directly proportional to the chosen variable and the other independent of that variable." *Electrical Engineering Economics*, Vol. 2: *Costs and Tariffs in Electricity Supply*, 2d ed. (London, 1951), p. 125.

Interstate Commission, in its estimates of the "long-run out-of-pocket costs" of railroad full-carload-lot freight traffic, "takes the out-of-pocket costs at 80 per cent of the total operating expenses, rents and taxes, plus an allowance for the cost of the long-run variable capital investment taken at 4 per cent (after income taxes) on all the equipment and about half the road property." [9] That is to say, 20 per cent of the operating expenses at any given rate of traffic density, and about half of the assumed 4 per cent capital costs of the road property, are treated as if they will not increase with small increments in traffic. In consequence, a 1 per cent increase in traffic would be assumed to increase operating expenses, etc. by $\frac{8}{10}$ of 1 per cent, to increase the annual capital cost of the equipment by 1 per cent, and to increase the annual capital cost of the road property by $\frac{1}{2}$ of 1 per cent. Referring to this procedure of long-run out-of-pocket cost analysis in 1954, Mr. Ford Edwards, who directed the development of the procedure in the late 1930s, writes: "The long-run rail freight out-of-pocket costs in the aggregate, as computed by the Cost Section, run to some two-thirds of the rail carriers' total revenue requirements, including the going rate of return and the passenger and LCL deficits when they occur. This leaves about one-third of the aggregate revenue requirements from freight to be apportioned as 'burden' on a value-of-service basis." [10]

I stress the above-noted distinction between so-called "constant" and "variable" costs even in long-run marginal-cost determination because of the pronounced tendency of recent writers on cost analysis to insist that no costs of producing utility or railroad services will fail very long to respond to changes in rates of output.[11] This insistence might be taken to discredit any long-run marginal cost analysis which makes use of the concept of constant costs. But no such wholesale condemnation of the practice would be warranted, since it would fail to recognize the convenience of the mathematical device of a "pseudo constant cost," for purposes of rough approximation.

Long-run marginal costs may vary with changes in rates of out-

[9] Quoted from Ford K. Edwards, "Transportation Costs, Value-of-Service and Freight Rates," 21 *I.C.C. Practitioners' Journal* 494–510 at 494 (1954).

[10] *Ibid* at 494–495.

[11] See, e.g., H. A. A. De Melverda, "The Illusion of Fixed Costs," *International Economic Papers*, No. 2 (London and New York, 1952), pp. 155–177.

put measured along more than one dimension. Although, with the two qualifications noted in the preceding paragraphs, all production costs of utility services must be deemed variable in the long run, it by no means necessarily follows that all of these costs vary with changes in rates of output or volumes of service measured in the same units, along one single dimension. In electric and gas utility cost analysis, for example, all or nearly all of the total operating and capital costs of production are often divided into three categories: those costs held to vary with the *number* of customers (customer costs); those costs held to vary with the supply of energy ("energy" or "volumetric" or "commodity" costs as measured in kilowatt-hours or in cubic feet of gas); and those costs held to vary with the maximum load imposed on the utility system (demand-related costs or capacity costs). But some cost analyses make use of a much finer and more detailed breakdown of cost functions.

A brief review of multidimensional, "functional-cost analysis" will be presented in the following chapter. But I mention the subject here merely in order to note the fact that marginal costs, especially though not exclusively those of the long-run variety, are by no means necessarily limited to marginal energy costs or to any other singly measured unit costs.[12] Thus, the long-run marginal costs of electric power supply at time of system peak may include allowances for marginal capacity cost, marginal energy cost, and marginal customer cost. And even estimates of short-run marginal costs may include allowances for costs other than energy costs, such as costs of meter reading and billing, which vary with number of customers.

MARGINAL COSTS OF PEAK VERSUS OFF-PEAK SERVICE UNDER SHORT-RUN AND LONG-RUN COST ANALYSIS

Unfortunately for the purpose of simple exposition, the distinction between short-run and long-run marginal cost, seldom very sharp at best, is further complicated by a situation that will receive much attention in the next chapter: that of a plant which operates chronically at, or close to, full capacity at certain times of day, week, or season but which has partly idle capacity at other

[12] See p. 219 of Vickrey's article already cited in footnote 6.

times. Here, the incremental or marginal cost of the off-peak service is of the character which we have called "short run" in that it embodies no incremental capacity cost. But here the plant redundancy is periodic and may even be permanent, since any increase in off-peak consumption may never catch up with whatever increase in plant capacity is provided in order to keep pace with increases in peak loads.

Even so, however, one may draw a distinction here between short-run and long-run marginal cost determination, although the distinction is now of a "mixed" nature. As to any clearly and permanently off-peak service (off-peak with respect to every part of a utility plant), so-called short-run analysis is the only applicable analysis. No component of plant capacity cost or capital costs should here be included in the estimate of marginal cost of service. But as to the peak-time service, there is a significant distinction between short-run and long-run marginal cost. Under short-run analysis, the marginal cost even of peak service includes only the incremental operating costs and excludes all capital costs or "capacity costs." But, for reasons already noted in the discussion of short-run marginal costs, these incremental operating costs may possibly be very high since they will include the incremental cost of production by the use of relatively inefficient equipment and since they may even include the "hazard costs" of operation with inadequate reserves or with temporary overloads. On the other hand, the *long-term* marginal costs of service supplied at times of system peak will include full allowances for whatever increments in capacity costs may be warranted in order to add to the supply of this type of service.

In the following chapter we shall note that the allocation of capacity costs respectively to on-peak and off-peak service illustrates a "limiting case" of joint-product pricing under conditions of pure competition—the case in which the one product (peak-time service) is the main product and the other product (off-peak service) is a by-product in its strictest, most extreme sense. Here, under the principles of competitive pricing, the price of the by-product would cover only its separable costs and would not share even to a slight extent in the coverage of the common costs.

COMPLICATION OF PLANT INDIVISIBILITIES

One further complication of long-run marginal-cost determination is that which arises because of the literal or practical indivisibility of some of the "factors of production"—particularly, of some of the larger units of plant and of heavy equipment.

In the *simpler* expositions of the behavior of the costs of a business enterprise in response to increases in rates of output, *continuously* rising output curves and total-cost curves are assumed—curves in which total cost rises smoothly with, though not necessarily proportionately to, the increasing rates of output. With rapidly expanding public utility systems, this assumption of continuity may give a sufficiently close approximation to the real-life uptrends in total costs to serve the purposes of rate determination. But at times the discrepancies between this assumption and actual cost behavior become serious enough to be of concern to the rate maker. These are times when plant expansion, either as a matter of utter necessity or as a matter of good economy, takes place in fairly large jumps.

The classic example of such a jump is that of a railroad which expands its line-haul capacity by shifting from a single to a double track. But many similar examples apply to the expansion of the urban utilities. Thus, in order to take advantage of the recognized economies of large-scale turbogenerators, an electric company may plan its program of expansion so that its output will first encroach on its reserves pending the completion of a gigantic generating unit, after which time the reserve may be excessive for the next year or more. And thus a telephone, electric, or gas company, in order to minimize the long-run costs plus the inconveniences of network installations involving the tearing up of city streets, may install all at once distribution capacity adequate for an estimated growth in load over the next several years.

Under these circumstances of a "jumpy" program of plant expansion, how does one measure the marginal costs of supplying the service? If the question concerns the determination of short-run marginal costs, the answer is relatively simple. Marginal costs of this type ignore capital costs in any event, regardless of the rate of expansion. Hence, if an electric utility company has just put into operation a gigantic turbogenerator which makes its power capacity temporarily excessive, marginal cost will drop correspondingly, only to rise again as the increase in plant utilization shifts from one of redundancy to one of shortage of reserve capacity. If utility rates were to follow these changes in short-run marginal costs, they too would rise and fall like waves—clearly an impractical situation.

But if our concern is to determine *long-run* marginal costs—incremental unit costs that may be expected to remain relatively stable despite temporary changes from situations of plant overcapacity to plant undercapacity—the problem is not so easy. Here, one must attempt some estimate of *average* incremental costs per unit of output over the life of the indivisible asset. This possible solution is fraught with difficulties. But so, for that matter, is the solution of *any* problem of long-run utility cost imputation.

SHORT-RUN VERSUS LONG-RUN MARGINAL COSTS AS MEASURES OF MINIMUM RATES

Having noted in the preceding section the very striking differences that are likely to prevail at any given time between short-run and long-run marginal costs, we may now consider the relative importance that should be attached to these two types of cost in the design of the rate structure. The question takes on a sharper form when raised under a proposal that all rates be fixed at mere marginal cost—a proposal to be discussed in Chapter XX—than it does when raised subject to the constraint that rates as a whole must be made to cover total costs. But we may discuss the question here under the assumption of this constraint and with reference to the use of marginal cost or incremental cost as a measure of *minimum* rates. Unfortunately, no simple answer to this question of choice is acceptable, since it presents one of the many dilemmas of rate-making policy.

THE CASE FOR SHORT-RUN MARGINAL COSTS

The argument in favor of short-run marginal costs as a basis of minimum rates can be stated briefly by the proposition that the costs which should govern the rates to be charged at any given time are the costs that actually prevail at this time and not the costs that will or would prevail on the average during an indefinite period in the future. These current costs are governed by the relationship between the present output of service and the present capacity of the plant. If this capacity is temporarily excessive, the rates for services in elastic demand should be brought down toward the temporarily low marginal costs in order to encourage consumers to make full use of the excess as long as it lasts. On the other hand, if plant capacity is inadequate, rates should be raised temporarily to the high short-run marginal costs of services in order to put the limited capacity to its most urgently demanded use and in order to avoid any overt rationing of service or any waiting list of unsatisfied potential customers.

If the present capacity of the utility plant and equipment happens to be optimum for the existing output of service, the problem of a proper choice between the two types of marginal cost will not arise, since under this condition the two costs will coincide. But when capacity and output are not in ideal balance, which is likely to be either a chronic or a frequently recurring situation, rates should then be related to the temporarily and "abnormally" high or low marginal costs, partly for the purpose of adapting the current demand for service to available supply and partly for the purpose of encouraging a speedier upward or downward adjustment of plant capacity to the anticipated future demand.

This view that utility rates should approximate short-run marginal costs, at least to the maximum extent permitted by the requirement that rates in the aggregate must cover total costs, is in accord with the view that public utility rate making should accept competitive-price standards of reasonable rates and rate differentials. For, under the theories of pure or perfect competition, prices are supposed to tend to come much more quickly into accord with short-run marginal costs than into accord with long-run marginal costs.

THE CASE FOR LONG-RUN MARGINAL COSTS

Even defenders of short-run marginal costs as the proper measures of minimum utility rates and rate relationships would concede the practical objections to cost determinations of such a volatile, extremely short-run character that changes in rates could not feasibly be made to keep pace with changes in costs. Public utility and railroad rate making, especially when subject to regulation

by administrative commissions, is a notoriously expensive and cumbersome procedure, with the result that new rates cannot be made to supersede old rates with anything like the rapidity with which an unregulated enterprise may find it feasible to change its quoted prices.

But the defenders of long-run marginal-cost or incremental-cost rate making would not be satisfied with this minor concession to the need for a leisurely procedure of rate regulation. For they would insist on the need for even greater stability in rate levels and in rate structure than that which would be imposed by the duration of a rate case. This asserted need rests on the view that the rates which play the major role in controlling the types and amounts of use of public utility services are those rates which are expected to prevail over a considerable period of time—probably over the next several years. It is these longer-run, anticipated rates, when compared with anticipated prices for substitute products or services, on which individuals must rely in making rational decisions whether to install oil-heating or gas-heating furnaces; whether to buy gas ranges or electric ranges for the kitchen; whether to locate an aluminum-reduction plant near the source of hydroelectric power on the St. Lawrence River or to locate it instead near the source of low-cost steam-electric power in the Ohio Valley, etc., etc. Once these commitments have been made, the demand for utility services consequent thereon will be largely predetermined by the consumers' investment in equipment and will depend only to a minor extent on any temporary changes in rates of change. In other words, the demand for public utility services is likely to be much less elastic in the short-run than in the longer run.[13]

To be sure, the rate schedules now on file are likely to have a

[13] On the relatively low elasticity of short-run demand curves, see Stigler, *The Theory of Price*, p. 47. In support of long-run marginal cost as a factor in rate making, see Donald H. Wallace, "Joint and Overhead Cost and Railway Rate Policy," 48 *Quarterly Journal of Economics* 583–619 (1934). Commissioner Joseph B. Eastman of the Interstate Commerce Commission said: "While some shippers gain a temporary advantage from unstable and unpublished rates, the greater present good and the long-run good of all require that the transportation factor in the cost of doing business be known and predictable." *Regulation of Transportation Agencies*, Sen. Doc. No. 152, 73d Congress, 2d Session (1934), p. 22. But on the allegedly exaggerated value of stable prices, see Frederick V. Waugh, "Does the Consumer Benefit from Price Stability?" 58 *Quarterly Journal of Economics* 602–614 (1944).

decided effect on those decisions of potential customers which will govern their future uses of utility services. But this effect will depend primarily on consumers' assumptions that the currently published rates, even if subject to fractional increases or decreases as a result of a new rate case, will not undergo a change in their general orders of magnitude or in their general relationship to the prices of substitute services or commodities.

In view of the above-noted importance attached to existing utility rates as indicators of rates to be charged over a somewhat extended period in the future, one may argue with much force that the cost relationships to which rates should be adjusted are not those highly volatile relationships reflected by short-run marginal costs but rather those relatively stable relationships represented by long-run marginal costs. The advantages of the relatively stable and predictable rates in permitting consumers to make more rational long-run provisions for the use of utility services may well more than offset the admitted advantages of the more flexible rates that would be required in order to promote the best available use of the existing capacity of a utility plant.

The history of railroad and utility rate regulation in this country would supply numerous examples of the dangers of especially low "incremental cost" rates which, at the time of their establishment, seemed well justified by their compensatory character but which, at a later time, failed to cover even their out-of-pocket costs.[14] What happened here is that the low rates, originally designed to promote greater use of a temporarily redundant plant, helped to stimulate demand to such an extent that the plant became inadequate, with the result that the incremental or marginal costs of the service rose to levels equal to or even above average total costs. Such a situation arose in New York State and elsewhere

[14] On the danger of promotional rates based on temporarily low incremental costs, see Hubert F. Havlik, *Service Charges in Gas and Electric Rates* (New York, 1938), pp. 59–60. This danger was emphasized by Milo R. Maltbie during his chairmanship of the New York Public Service Commission, e.g., in N.Y. Central R.R. Co. Rates (Commutation Fares), Case 6533, P.U.R. 1932C 75. Mr. John Alden Bliss, a transportation economist, calls my attention to a classic example of this danger in railroad rate making: namely, to James J. Hill's low eastbound lumber rates, which finally created a new eastbound peak and a consequent need to haul empties westbound. "Such low rates," writes Mr. Bliss, "are difficult to correct, even without presuming regulation." The influence of vested interests in established railroad-rate relationships is discussed by Professor I. L. Sharfman, *The Interstate Commerce Commission*, Vol. III B (New York, 1936), pp. 667 *et seq.*

with respect to the manufactured-gas companies, which at one time offered sharply reduced rates to users of the gas for house heating in order to put to fuller use plants that had been made redundant by the competition of electricity. Even before the coming of natural gas, house-heating use in some areas had enhanced the demand for manufactured gas beyond the capacity of the existing plants, with the result that the heating rates ceased to be compensatory. The companies sought, and finally secured, permission from the public service commission to raise these rates; but only after a considerable delay, during which time consumer spokesmen complained that they had installed gas furnaces "on the faith" of the persistence of the favored rates.

But one should not conclude from the foregoing remarks that the danger from rates based largely on temporarily low, short-run marginal costs is a danger never worth running. Indeed, something can be done to minimize the danger through the issuance by a public utility company and by a regulatory agency of clear-cut warnings that especially low rates, designed to make the best feasible use of temporarily excessive plant capacity, are subject to cancellation on very short notice. Thus, during the 1930s, the Ontario Hydro-Electric Power Commission, which supplies the Province of Ontario with most of its electric power and which was then faced with a gross excess in water-power capacity, granted phenomenally low temporary rates to industries which used the power to heat boiler water and to serve other "low-grade" purposes. Indeed, the familiar American use of low rates for "interruptible power" (interruptible within limitations) and of still lower rates for "dump power" (interruptible with few if any limitations) serves the same general purpose.

As to the possible use of a high short-run marginal cost as a measure of rates when the existing capacity of a utility system will not suffice to supply all service that would be demanded at "normal" rates of charge, the practical and political objections to this practice have been deemed so serious that resort to overt rationing or to the policy of first come, first served has been the accepted alternative. For reasons suggested in an earlier chapter,[15] these objections seem to me not merely serious but almost fatal if the public utility in question is operating under private ownership.

[15] Pp. 98–99, *supra*.

I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant marginal or incremental costs are those of a relatively long-run variety—of a variety which treats even capital costs or "capacity costs" as variable costs. Short-run marginal costs should not be ignored. But they should be used with caution, and with special warnings of the liability of rates based thereon to cancellation or revision on short notice.

XVIII

FULLY DISTRIBUTED COSTS

As already noted in Chapter XVI, writers on the economic principles of public utility rates have suggested that, when the rates of any given utility enterprise must be made to cover total costs of production even though the enterprise is operating under conditions of declining unit costs (of unexhausted economies of scale), each individual rate should be made up of two components: a minimum price set at the marginal cost of the service, and a surcharge or quasi tax designed to contribute some appropriate share of those additional revenue requirements which would fail to be covered if all rates were to be held down to their minima. While even the surcharge would not be independent of marginal cost, its relationship thereto would not necessarily be a simple one and might well be deliberately "biased" by value-of-service considerations. The same idea is implicit in the more popular but cruder assertion that public utility and railroad rates should be set somewhere between "cost of service" (that is, out-of-pocket or marginal costs) as a lower limit and "value of service" (that is, what the traffic or market will bear) as an upper limit.

In actual practice, however, rate structures are seldom built up in this two-step manner. Instead, if based on any comprehensive cost analysis at all (which appears to be true in only a tiny minority of cases) they are derived analytically, not synthetically, from apportioned total costs of service. Thus, with an electric utility company, the analyst may first distribute total annual costs among nine classes of service, more or less: residential, commercial, industrial power, street lighting, etc. He may then redistribute the costs of each class among the units of service within this class, distinguishing among customer units, energy units (kilowatt-hours), and maximum-demand units (kilowatts). The first apportionment is supposed to indicate the aggregate revenues that would be due from each class of service if rates were to be based solely on costs of production. The second apportionment is supposed to serve as a guide to the determination of the pattern of each class rate—a pattern that may be composed of a minimum monthly charge per customer, a set of declining block-energy charges, and (for larger consumers) a set of declining block-demand charges.

Even those experts who make and defend these apportioned total costs in rate cases before public service commissions or courts seldom, if ever, offer them as final measures of reasonable rates and rate relationships. Instead, they concede that rates which deviate substantially from the cost apportionments may be justified by a variety of noncost considerations. This concession goes to the point of recognizing the validity and compensatory character of "competitive" or "promotional" rates, such as one for large industrial power, which fail to cover the very costs which the analysts have imputed to the class of service in question.

But there remains the question what, if any, significance should be attached to these fully distributed costs even as guides, or even as points of departure for rate determination, in view of the admitted fact that they fail to mark the dividing line between compensatory and noncompensatory charges for particular classes or quantities of service. And to this question the customary answers are woefully inadequate. The reply most frequently offered is that cost of service is only one of several factors to be considered in rate-structure determination. But this assertion, while quite valid, is also quite beside the point. For the question at issue concerns the doubtful meaning and significance of apportioned total costs and not the weight to be given to a clearly defined specific cost as a basis of rate making.

Mindful of the widespread failure of the cost analysts themselves to supply a really satisfactory answer to this critical question, and mindful also of the notorious disagreements among the experts as to the choice of the most rational method of overhead-cost allocation—a disagreement which seems to defy resolution because of the absence of any objective standard of rationality—public utility managements and public service commissions have often denied or doubted the value of comprehensive total-cost apportionments even as useful guides to rate-structure design. Their doubt is fortified by recognition of the heavy expense and time-consuming character of any thoroughgoing cost analysis as well as by an awareness of the danger that unsophisticated participants in a rate case may be under the illusion that the apportioned costs mean what they seem to mean.

This adverse or skeptical attitude of many public utility companies and public service commissions toward fully distributed cost apportionments may well be justified.[1] But one should not condemn the procedure too hastily, for it is not devoid of at least a *plausible* rationale. What, then, is this rationale? This is the primary question for discussion in the present chapter.

FULLY DISTRIBUTED COSTS AS FIRST APPROXIMATIONS OF MEASURES OF REASONABLE RATES

Fully distributed cost analysis is of many different types, and only within limits do these types have the same rationale. But common to most of them when used as a basis of rate making is the view that the

[1] The extent to which electric companies make such apportionments for their private use, or in order to have them available if they should be demanded by a commission, is not a matter of record. But comprehensive apportionments have been presented officially in only a tiny fraction of the rate cases. In Re Pacific Gas and Electric Co., Oct. 15, 1952, 96 PUR NS 493, 529–530, where the company presented an analysis of class costs of electric service, the California Commission remarked: "Here for the first time in recent years in a formal rate case the Commission has before it functional cost computations to aid in the determination of proper rate levels." Yet this commission is a recognized leader in its review of rate structures. One of the most elaborate cost-apportionment studies was made in Re Consolidated Edison Co. of New York, Inc., 96 PUR NS 194, a case instituted in May 29, 1946, and not decided until July 14, 1952! Even here, however, the "allocations were concerned primarily with the allocation of cost between different classes of service rather than the rate structure within each class." (Separately printed opinion, p. 269). In a now-pending electric rate case of the same company, the New York Commission has ordered the company, over its objections, to make a comprehensive cost breakdown. But in 1953 and 1958 (24 PUR 3d 209, 214), the Commonwealth Edison Company successfully resisted intervenors' appeals to the Illinois Commerce Commission for a ruling requiring a similar breakdown. See n. 11, *infra*. In Matter of Suspension of Rates of the Union Electric Co., Case 14,039, July 16, 1959, the Missouri Public Service Commission said: "Cost analyses . . . which depend on arbitrary bases of apportionment of investment and expenses . . . are subject to erroneous assumptions and conclusions and merit only limited consideration. . . ." Two recent decisions declining to require cost analyses in support of rate-increase applications are Produce Terminal Corp. v. Illinois Commerce Commission, 414 Ill. 582, 112 N.E. 2d 141 (1953); and City of Pittsburgh v. Pennsylvania Public Utility Commission, 171 Pa Super 187, 90 A 2d 607 (1952). But the Federal Power Commission uses full-cost apportionments in setting or approving wholesale rates of natural-gas pipeline companies. See p. 354, n. 16, *infra*.

apportioned costs are useful as first approximations of reasonable rates—approximations based on the provisional assumption that rate relationships should depend entirely on cost relationships. Carefully to be excluded, therefore, are all noncost factors—factors such as those based on statutory mandates (for example, a mandate that preferential rates must be given to residential consumers); or on political or social considerations (for example, considerations favoring low rates for churches or for low-rental housing); or on the vested interests of existing customers who may have acted in reliance on the continuance of the old rates; or, above all, on value-of-service differentials. While all of these factors are arguably entitled to some weight in the design of the rate structure, their recognition is beyond the purview of the cost analyst, who should seek to confine his estimates to the determination of the behavior of costs in response to the changes in rates of output of various services, without incorporating "value judgments" about the bearing of this observed behavior on the fairness or reasonableness of the charges for the service.

But what, then, is the meaning of total-cost apportionments which admittedly do not reflect differential or incremental costs and which therefore fail to mark the dividing line between compensatory and noncompensatory charges for different types of service? The only plausible answer, in my view at least, is that these apportionments should be designed to reflect *relative* differential or incremental or marginal costs, not absolute costs.[2] If, for example, the apportionment of the total annual costs of supplying electric utility services were to impute $5,000,000 of these costs to residential service and $2,500,000 to small-commercial service, this imputation should imply that the incremental costs of the former class of service, whatever they may be, are much greater than the incremental costs of the latter. And it may even be designed to indicate (although by no means all cost analyses are so designed) that the former incremental costs are twice as high as the latter. But what it should not be assumed to assert is that the respective sums of $5,000,000 and $2,500,000 per annum represent the respective annual costs of the two classes of service. These costs, were they to be measured, would be differential costs and hence, save under exceptional conditions, would be nonadditive.

[2] Supporters of fully distributed cost apportionments have sometimes defended them as measures of relative rather than absolute costs. In Re Consolidated Edison Co., July 14, 1952, the New York Public Service Commission said: "Cost of service studies, even when they include all classes of service, are not acceptable as representing absolute, precise values; they are, rather, relative indications of costs." 96 PUR NS 194 at 395. For this reason, the Commission belittled any studies limited to a single class of service. Compare Donald M. Henry's statement that, while cost apportionments are "more or less arbitrary," they have some value as showing relative changes in costs of the same classes of service over periods of time: "What is the Cost of Service: What is Equitable Allocation?" 93 *Gas Age*, May 4, 1944, pp. 58–60 and 106.

Fully apportioned costs, then, should reflect cost relationships, not absolute costs. But beyond saying that the relationships should be among incremental or marginal costs, one cannot generalize as to their precise nature, since in this respect the analyses are not uniform. A relationship of direct proportionality suggests itself and is perhaps the most generally useful one for rate-making purposes.[3] But it is rejected sharply, for example, by the Cost Section of the Interstate Commerce Commission in its apportionment of so-called "constant costs" or "burden."[4]

The particular cost relationship apparently sought for by most cost analysts is one that would measure those rate relationships which could be called "completely nondiscriminatory." These hypothetical, cost-related rates could then be used as points of departure from which to derive actual rates which would incorporate desirable types and degrees of discrimination while avoiding discrimination that could be deemed "unjust" or "undue."

[3] See p. 375, *infra*.

[4] Interstate Commerce Commission, Bureau of Accounts and Cost Finding, "Explanation of Rail Cost Finding Procedures and Principles Relating to the Use of Costs," Statement No. 4, p. 54; Samuel A. Towne, Chief, Cost Finding Section, I.C.C., "Cost Level Guides to Rate Making," 21 *I.C.C. Practitioners' Journal* 697–707 (1954); Ford K. Edwards, "Transportation Costs, Value-of-Service and Freight Rates," 21 *I.C.C. Practitioners' Journal* 494–510 (1954); Edwards, "Cost Analysis in Transportation," 37 *American Economic Review, Proceedings* 441–461 (May, 1947). Dudley F. Pegrum discusses the uses made of these fully distributed costs in an article on "The Economic Basis of Public Policy for Motor Transport," 28 *Land Economics* 244–263 (1952). And see the reference to them by Justice Douglas, speaking for the Supreme Court in New York v. United States, 331 U.S. 284, 316 (1947), footnote 21: "The sum of the out-of-pocket costs plus a pro rata distribution of the constant or fixed costs is referred to as fully distributed costs." In a leading rate case, Northern Pacific R. Co. v. North Dakota 236 U.S. 585, 597 (1915), the Supreme Court said: "The outlays that exclusively pertain to a given class of traffic must be assigned to that class, and the other expenses must be fairly apportioned. It may be difficult to make such an apportionment, but when conclusions are based on cost the entire cost must be taken into account." This oft-quoted statement is very confusing from the standpoint of cost analysis. For the apportionment of "the other expenses" in such a way as to portray true costs, instead of being "difficult," is literally impossible.

Unfortunately, however, and for reasons to be discussed in the following chapter, no rate relationships can be made completely nondiscriminatory as long as all or some of the rates must be set above marginal costs in order to yield adequate revenues. And this fact may explain some of the disagreements among the experts as to the more rational formulas for the apportionment of total costs among different units of service. One such disagreement, which will receive attention in this next chapter, concerns the question whether rates for different kinds of service, in order to avoid the attribute of discrimination, must be made directly *proportional* to marginal costs, or whether they should be based instead on *differences* in marginal costs. Here, the choice is that between the horns of a dilemma.

TWO MAJOR TYPES OF FULLY DISTRIBUTED COST ANALYSIS

1. THE DOUBLE-STEP TYPE

Despite an ambiguity due to its failure clearly to define "relative costs," the above exposition of fully distributed costing goes about as far as one can go toward expressing the basic philosophy of the practice. For more explicit expositions, one must distinguish different types of analyses. By all means the most important distinction is that between those total-cost apportionments which superimpose a distribution of admittedly unallocable cost residues on estimates of incremental or marginal costs, and those other apportionments which recognize no difference between true cost allocation and mere total-cost distribution.

The first, or double-step, type might also be called the "railroad type" because of its application to railroads (and other transportation agencies) by the Cost Section of the Interstate Commerce Commission. The Cost Section distinguishes between (directly) variable costs and constant costs in a manner noted in the preceding chapter. The variable costs alone are assigned to the different units of freight traffic as representing "long-run out-of-pocket costs"—a term with a meaning here not distinctly different from that of the economist's "long-run marginal costs." There remains a residue of total costs, or total "revenue requirements"

which, since it is found to behave as if it were constant over substantial variations in traffic density, is strictly unallocable on a cost-finding basis. Nevertheless, because the Cost Section has felt impelled to make some kind of a distribution of total costs, it has apportioned this residue, which it sometimes calls "burden," among the units of carload traffic on a basis (partly ton, partly ton-mile) which is concededly quite arbitrary from the standpoint of cost determination. In recent years, this burden (which includes allowances for revenue deficiencies in the passenger business and in less-than-carload freight traffic!) has amounted to about one third of those total revenue requirements which the carload freight business is supposed to be called upon to meet.

Since this book is concerned only incidentally with railroad rates, it will not attempt to analyze the methods by which the staff of the Interstate Commerce Commission has estimated out-of-pocket costs and apportioned residue costs. Suffice it to say that the usefulness of the latter apportionment is questionable. But in any event, full credit should be given to the Cost Section for its express and overt recognition of a vital distinction too often ignored in utility-cost analyses: namely, that between a cost allocation designed to reflect the actual behavior of costs in response to changes in rates of output of different classes of utility service; and a mere cost apportionment which somehow spreads among the classes and units of service even those costs that are strictly unallocable from the standpoint of specific cost determination.[5]

2. THE SINGLE-STEP TYPE

We turn now to a type of fully distributed cost analysis which, unlike the "railroad type," draws no distinction between cost allocation and cost apportionment: the single-step type.[6] It might be called the "public utility" type because of the considerable use to which it has been put in gas and electric utility rate cases. Here

[5] But, in the actual design of rate structures, the local public utilities have made far better use of their cost analyses, despite deficiencies, than the railroads and the Interstate Commerce Commission have made of whatever analyses have been at their command.

[6] See Russell E. Caywood, *Electric Utility Rate Economics* (New York, 1956), Chap. 11; L. R. Nash, *Public Utility Rate Structures* (New York, 1933), Chap. 11; and the much more elaborate treatment by D. J. Bolton, *Electrical Engineering Economics*, Vol. 2: *Costs and Tariffs in Electricity Supply*, 2d rev. ed. (London, 1951), Chaps. 4 to 8.

no attempt is made, first to determine out-of-pocket or marginal costs and then to superimpose on these costs "reasonably distributed" residues of total costs. Instead, all of the total costs are treated as variable costs, although these costs are divided into costs that are deemed to be functions of different variables. Moreover, whereas in Interstate Commerce Commission parlance "variable cost" means a cost deemed to vary in *direct* proportion to changes in rate of output, in the type of analysis now under review "variable cost" has been used more broadly, so as to cover costs which, while a function of some one variable (such as output of energy, or number of customers), are not necessarily a *linear* function.

As already noted in an earlier paragraph, the more familiar cost analyses of utility enterprises or utility systems divide the total costs among a number of major classes of service, such as residential, commercial, industrial power, street lighting, etc. This "grand division" permits many costs to be assigned in their entirety to some one class, such as street lighting, or at least to be excluded completely from some important class or classes. High-tension industrial power service, for example, would not be charged with any share of the maintenance costs or capital costs of the low-tension distribution lines. But the major portions of the total costs of a utility business are common or joint to all, or nearly all, classes of customers; and these costs must somehow be apportioned among the various classes and then must somehow be reapportioned among the units of service in order to report unit costs that can serve as tentative measures of reasonable rates.

The general basis on which these common costs are assigned to differently measured units of service will be illustrated by the following highly simplified problem of an electric-utility cost analysis. But before turning to this example, we must distinguish two subtypes of analysis, both of which belong to the single-step type rather than to the double-step type.

In the first subtype, the analyst (following the practice of railroad analysis in this particular respect) distributes both total operating costs and total annual capital costs (including an allowance for "cost of capital" or "fair rate of return") among the different classes and units of service. Here, an apportionment, say, of $5,000,000 of the total costs to residential service as a class would include an allowance of perhaps 6 per cent as the cost of whatever capital is deemed to have been devoted to the service of the residential consumers.

But in the second subtype, which I take to be the one more frequently applied, only the operating expenses and not the "cost of capital" or "fair return" are apportioned directly among the various classes of service. To be sure, the capital investments in (or, alternatively, the estimated "fair values" of) the plant and equipment are apportioned among the different classes, as are also the gross revenues received from the sales of the different services. But any resulting excess of revenues received from a given class of service over the operating costs imputed to this class is reported as a "return" realized on the capital investment attributed to the same service. Thus, during any given year (a) if the revenues from the residential service are $7,000,000, (b) if the operating expenses imputed to this class of service come to $5,000,000, and (c) if the net investment in (or value of) the plant and equipment deemed devoted to this service amounts to $30,000,000, the cost analyst will report that residential service, in the aggregate, has yielded a return of $2,000,000 or 6⅔ per cent. Other services will show different rates of return, some probably much lower and some higher.

There are obvious reasons of convenience for this practice of excluding "cost of capital" from the direct apportionment of annual costs among the different classes of service—notably, the avoidance of the controversial question what rate of return should be held to constitute "cost of capital" or "fair rate of return." But the practice is likely to be misleading, since it may seem to support a conclusion that, as long as the revenues from any class of service cover the imputed operating expenses plus *some* return on capital investment, however low, the rates of charge for this service are compensatory. Needless to say, any such inference would be quite unwarranted.

For the reason just suggested, I shall assume the use of the first subtype of fully distributed cost apportionment in the following simplified example. That is to say, an allowance for "cost of capital" will be assumed to be included directly in the cost apportionment.

THREE-PART ANALYSIS OF THE COSTS OF AN ELECTRIC UTILITY BUSINESS

In order to simplify the exposition of a typical fully apportioned cost analysis, let us assume the application of the analysis to an electric utility company supplying a single city with power generated by its own steam-generation plant. Let us also assume the existence of only one class or type of service, all of which is supplied at the same voltage, phase, etc. to residential, commercial, and industrial customers. This latter assumption will permit us to center attention on the most controversial aspect of modern public utility cost analysis—the distinction among costs that are functions of outputs of the same service measured along different dimensions.

Since the company under review is supplying what we are here regarding as only one kind of service, we might suppose that the problem of total cost apportionment would be very simple; indeed, that it would be limited to a finding of the total annual operating and capital costs of the business, followed by a calculation of this total in terms of annual cost per kilowatt-hour of consumption. In fact, however, the problem is not so simple. For a statement of costs per kilowatt-hour would ignore the fact that many of these costs are not a function of kilowatt-hour output (or consumption) of energy. A recognition of multiple cost functions is therefore required.

The simplest division, and the one most frequently used (with subdivisions) in gas and electric rate cases, is a threefold division of the total operating and capital costs into "customer costs," "energy" or "volumetric costs," and "demand" or "capacity" costs.[7] If this threefold division of costs were to have its counterpart in the actual rates of charge for service, as it actually does have in some rates, there would result a three-part rate for any one class of service. For example, the monthly bill of a residential consumer might be the sum of a $1 customer charge, a $5 charge for 250 kilowatt-hours of energy at 2¢ per kilowatt-hour, and a $2 charge for a maximum demand of 2 kilowatts during the month at the rate of $1 per kilowatt—a total bill of $8 for that month. But our present interest lies in the measurement of costs of service, and only indirectly in rates that may or may not be designed to cover these costs. Let us therefore consider each of the three types of cost in turn, recognizing that this simplified classification is used only for illustrative purposes; costs actually vary in much more complex ways.

[7] Other cost breakdowns, such as those allowing for the power factor, for voltage differences, for distances between points of generation and points of consumption, and for the customer-density factor, have been used to a limited extent. Compare Vickrey's selection of six parameters in order to approximate the response of the operating costs of the New York City Rapid Transit System to various changes in service and traffic: Train miles; car miles; maximum number of cars in service; number of passengers carried; number of passengers carried during the peak hour; and the layout of the system, consisting of the number of route miles, number of stations, etc. William S. Vickrey, *The Revision of the Rapid Transit Fare Structure of the City of New York.* Technical Monograph No. Three, Finance Project, Mayor's Committee on Management Survey of the City of New York, Feb., 1952, p. 8.

1. THE CUSTOMER COSTS

These are those operating and capital costs found to vary with number of customers regardless, or almost regardless, of power consumption. Included as a minimum are the costs of metering and billing along with whatever other expenses the company must incur in taking on another consumer. These minimum costs may come to $1 per month, more or less, for residential and small commercial customers, although they are substantially higher for large industrial users, who require more costly connections and metering devices. While costs on this order are sometimes separately charged for in residential and commercial rates, in the form of a mere "service charge," they are more frequently wholly or partly covered by a minimum charge which entitles the consumer to a very small amount of gas or electricity with no further payment.

But the really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system—a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage and to keep from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized distribution system are treated as

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customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary indirectly with the number of customers.

What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Indeed, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.

While, for the reason just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible,[8] its exclusion from the demand-related costs stands on much firmer ground. For this exclusion makes more plausible the assumption that the *remaining* cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load.

But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But the fully-distributed cost analyst dare not avail

[8] This is in accord with the views of Hubert F. Havlik: *Service Charges in Gas and Electric Rates* (New York, 1938), Chap. 8 and Appendix A. Allocation, in whole or in part, would be at least theoretically possible if a customer-density parameter were added to the three traditional cost components. See G. P. Watkins, *Electrical Rates* (New York, 1921), p. 212. But if this factor were embodied, not only in cost analysis but in the resulting rate differentials, rates would not be uniform throughout a given community and hence would violate a generally accepted tradition.

himself of this solution, since he is the prisoner of his own assumption that "the sum of the parts equals the whole." He is therefore under impelling pressure to "fudge" his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other cost categories.

2. THE ENERGY COSTS

The energy-cost component of this threefold division of total annual costs is supposed to consist of those costs which would vary with changes in consumption of energy, measured in kilowatt-hours, even if the number of customers should remain constant and even if there were no change in maximum load upon the system or subsystem as measured by kilowatts or kilovolt amperes.[9] The most obvious costs of this character are fuel costs, although a small portion even of these costs may be regarded as demand-related on the ground that some fuel is required in order to maintain a "spinning reserve." But other operating costs may also be deemed to vary with output of energy and hence with consumption of energy, including whatever depreciation of the equipment may be regarded as a function of use rather than of obsolescence and aging.

Reduced to costs per kilowatt-hour, the imputed energy costs may be only a fraction of total average costs. It is this relative smallness which is often held to justify a company in conceding very low rates for off-peak or interruptible services, on the ground that these services impose upon the company little or no additional capacity costs.

The treatment of energy costs as a separate cost function is subject to one serious deficiency: namely, in its assumption that the

[9] Estimates of the ratio of energy-related costs to total costs of electric supply (including capital costs) have ranged from 1/3 down to only 1/4. Referring to British conditions, Bolton writes: "More accurate costing has shown that, on the average, only one-quarter of the total costs of electricity supply are represented by coal or items proportional to energy, whilst three-quarters are represented by fixed costs or items proportional to power, etc." D. J. Bolton, *Costs and Tariffs in Electricity Supply* (London, 1951), p. 59. But he notes two practical reasons, among others, why this situation does not justify a corresponding dominance of demand charges rather than energy charges in electric rate structures: (a) that the effective power demand imposed upon the system by any given individual is very difficult to determine, and (b) that a pure demand-charge rate would probably lead to a more serious waste of energy than a pure energy rate would lead to a waste of power capacity. The latter reason invokes a "value-of-service" or "demand-elasticity" principle of rate making rather than a cost principle.

cost to the company of producing any given amount of energy, measured in kilowatt-hours, is independent of the system load factor. For such an assumption may be belied by the fact that the turbogenerators which carry the company's base load will be much more efficient than those generators which are relied upon to carry the peak loads. Hence, the cost analysis may be in danger of overstating the relative energy costs of off-peak service and of understating the relative energy costs of on-peak service. Recognizing this danger, the analyst may undertake to offset it by imputing to the peak-time consumers a lower capacity cost than would otherwise be deemed justified—a capacity cost based on a steeply written-down net investment in, or appraised value of, those older, less efficient turbogenerators that will be operated only for a few hours per day.

3. THE CAPACITY COSTS OR DEMAND COSTS

We come now to that category of costs, the treatment of which has made a nightmare of utility cost analysis.[10] For the problem which it presents is that of imputing joint costs to joint products or by-products, and not merely that of distributing those common but nonjoint costs which vary more or less continuously with number of consumers or with rates of output.

Here, as with the other two categories of cost, there is no general agreement as to what items or portions of total costs should be included among the demand-related costs, perhaps because cost functions are far too complex to be reflected by the arbitrary, three-way classification of customer, energy, and demand. But we may ignore this lack of agreement in order to turn attention to the far more critical problem of apportioning whatever costs have been found to be demand related. Suffice it to say that this category of costs includes the major part of the total allowance for depreciation, for property taxes, and for return on investment, together with a substantial part of the operating and maintenance expenses. Whether or not corporate income taxes should also be included, on the ground that they tend to vary with the earned return on investment in plant and equipment and hence indirectly with the capacity of the plant, is a question sometimes debated in the rate cases. But we may here pass this question with the note that the asserted correlation must be far from close.

[10] In addition to the references already cited in footnote 6, see the two technical reports (K/T 106 and 109) on demand-related cost allocations by special committees of the British and Allied Industries Research Association, 15, Savoy Street, London, W.C. 2, dated 1943 and 1945 respectively; W. Arthur Lewis, *Overhead Costs* (London, 1949), Chaps. 1 and 2; Ralph Kirby Davidson, *Price Discrimination in Selling Gas and Electricity* (Baltimore, 1955), Chap. 8; and a series of discussions on "Peak Loads and Efficient Pricing" in the *Quarterly Journal of Economics* by Professors Jack Hirshleifer, H. S. Houthakker, and Peter Steiner: 71 *Q.J.E.* 585–610 (1957); 72 *ibid.* 451–468 (1958). In one of these articles, Professor Hirshleifer refers to a masterly theoretical treatment of the subject by Marcel Boiteux, a distinguished engineer of Électricité de France: "La Tarification des demandes en pointe: Application de la théorie de la vente au coût marginal," 58 *Revue générale de l'électricité* 321–339 (1949). This article, with modifications, has been translated: "Peak-Load Pricing," 30 *The Journal of Business of the University of Chicago* 157–179 (1960).

Assuming, then, that an estimate has been made of total capacity costs, probably expressed in terms of costs per annum, the question now arises as to the proper apportionment among, or allocation to, services supplied at different load factors and at different times of day or season. These services share responsibility in different degrees, if at all, for the creation of the system and subsystem peak loads and hence indirectly for the capacity costs that must be incurred in advance in order to meet these loads.

In attempting to assess these relative responsibilities, the analyst is offered a wide variety of alternative formulas of apportionment, each of which has received support from some rate experts. Testifying before the Illinois Commerce Commission in a recent rate case, Vice President Gordon Corey of the Commonwealth Edison Company noted the existence of twenty-nine such formulas.[11] Most of them have no claim whatever to validity from the standpoint of cost determination, and only a dubious claim to acceptance as compromise measures of reasonable rates. Hence they will not be reviewed in this book. But, for illustrative purposes, we may mention

[11] Case No. 41130 before the Illinois Commerce Commission, *Objections of Commonwealth Edison Company to Motion of City of Chicago, Dated September 15, 1953, Respecting Cost of Service Studies.* In this brief the company stated that the making of a complete class-of-service cost study would require detailed analyses to determine the proper apportionment of over 6,000 different kinds of costs which the company had segregated according to functions or activities that cause such costs to be incurred. As a witness for the company in this case, I supported its objections to a class-cost analysis on the ground that, in order to be of any value, its preparation and critique would be formidably time consuming and would introduce controversial issues not essential to the timely solution of what was essentially a "revenue" or "rate-level" case.

three formulas that receive special attention in the latest American treatise on electric rates, by Mr. Russell E. Caywood of the West Penn Power Company.[12]

The first is the peak-responsibility formula. Here, the entire capital costs are imputed to those services that are rendered at the time of system (or subsystem) peak (probably at the time of the *annual* peak) and in proportion to the kilowatt demand imposed at this time—an integrated demand rather than an instantaneous demand, measured over some short period such as thirty minutes or longer. Service rendered completely off-peak would be assigned no responsibility whatever for the capacity costs.

The second formula is called the "noncoincidental-demand" formula.[13] Like the first, it apportions capacity costs entirely on the basis of kilowatts of load rather than on the basis of kilowatt-hours of energy. But it apportions these costs in proportion to the maximum demands of the different classes and of different individual consumers of service even though some of these demands, so far from coinciding with the peak load of the company, may be completely off the system peak. This type of cost apportionment, whatever merit may be claimed for it as a basis of rate making on grounds of "fairness," or on grounds of presumptive value-of-service considerations, is not really a cost analysis at all and should not be allowed to masquerade as such. Yet precisely this method of apportionment is said to have a wider currency than does any alternative method in American rate making.

The third formula is called the "average-and-excess-demand" method by Caywood, who points out that it reaches the same result, though by a different mathematical technique, as that reached by

[12] *Electric Utility Rate Economics* (New York, 1956), pp. 156–167.

[13] Economists have been particularly critical of this method. In the words of Professor W. Arthur Lewis, referring to attempts by rate engineers to offset its obvious infirmities by allowances for the different diversity factors of different groups of consumers, "no amount of correction can alter the fact that the standing costs of the undertaking are related not to the maximum rate at which the individual consumer takes, but to the amount he takes at the time of the station peak." *Overhead Costs* (London, 1949), p. 52. (But this sentence should have been amended to include not only station peak but distribution-system peak, which may be an even more critical factor.) In industrial-power rate making, the use of noncoincidental demand as the basis of the demand charge has been defended on the ground that the resulting two-part, Hopkinson rate follows the cost behavior of an isolated, private steam plant. Caywood, *Electric Utility Rate Economics*, p. 32. But this is a value-of-service argument and is not germane to an analysis of the costs actually incurred by the public utility company itself.

another method called the "Greene method." Here, the assumed cost of that portion of the company's plant capacity which would be needed even if all consumers were taking their power at 100 per cent load factor is apportioned among consumers in proportion to their average loads—that is, in proportion to their kilowatt-hour consumption of energy during the time period in question. But the assumed cost of the excess in actual plant capacity over this lower, hypothetical capacity is apportioned "by applying the non-coincidental peak method to the difference between maximum loads and average loads."

Like other formulas which, overtly or in effect, apportion a part of the capacity costs among kilowatt-hours of energy rather than entirely among kilowatts or kilovolt amperes, the "average-and-excess-demand method" has a certain degree of justifiable support from the standpoint of cost analysis. This support lies in the fact that, when the extent of coincidence between the maximum load of any given consumer and the peak system load cannot be measured or prophesied directly, one may be justified in assuming a greater *probability* of coincidence if the customer is operating on a high load factor than if he is operating on a low load factor. Thus, the maximum load of a 100 per cent load-factor consumer is *certain* to coincide at some point of time with system peak, whereas the maximum load (or, for that matter, even the entire load) of a 10 per cent load-factor customer may be entirely off the system peak. But when resort must be had to these "stochastic" or "probabilistic" methods of capacity-cost imputation, no general formula is worthy of much respect. Instead, empirical studies of the relationship between load factors and coincidence factors for different uses of service (air conditioning, water heating, elevator operation, etc.) are required. Such studies have been made by a number of companies, notably, by the Philadelphia Electric Company under the direction of its distinguished rate engineer, Mr. Constantine Bary.[14]

[14] See, e.g., "Economic Significance of Load Characteristics as Applied to Modern Electric Service," presented at 53d Annual Meeting, Association of Edison Illuminating Companies, Jan., 1938; "Coincidence-Factor Relationships of Electric-Service Load Characteristics," *Transactions*, American Institute of Electrical Engineers, Vol. 64, 1945; "Load-Structure of a Modern Electric Utility System," *Electric Light and Power*, May, 1954; "Load Characteristics of 'Small Light and Power' Customers—Their Economic Significance," *Electric Light and Power*, Oct. 15, 1955; "Dollars and Sense of Electric House Heating," presented at 75th Annual Meeting, Association of Edison Illuminating Companies, Nov., 1959.

Limitations of the various capacity-cost apportionment formulas. Of the three formulas just described, the one that would probably come closest to receiving support from the economists, at least viewed from the standpoint of cost analysis, is the system-peak responsibility method. At least there would be general agreement that, with qualifications noted in the footnote below,[15] the cost to a company of rendering any type of service which can be counted upon positively to stay off the system (or subsystem) peak does not include any capacity cost. Whether or not the rates actually charged for such a service should nevertheless attempt to recover parts of the company's capacity costs because of "value-of-the-service" factors, or else because of a widely held view that even off-peak users and interruptible power users should make some *fair* contribution to the costs of a plant which confers upon them a benefit, is another question—a question which, while related to that of cost imputation, is by no means necessarily tied thereto.[16]

But what, then, makes capacity cost allocation or apportionment such a highly controversial problem? The answer lies in the fact that capacity costs, instead of being ordinary overhead costs, common to different kinds of amounts of service, are *joint* costs—the costs of producing services which are joint products when they are rendered at different periods of time. So important for the purpose

[15] If an electric power station were constructed for the *sole* purpose of supplying a peak demand occurring, say, only one hour per day, less efficient and hence less expensive turbogenerators (possibly with gas turbines) would be installed for the sake of maximum economy. Hence, when stations are designed to supply a 24-hour variable load, the additional costs of the more efficient generating units are theoretically chargeable to off-peak use. Moreover, with run-of-the-river hydro-electric plants the system peak load is not necessarily the load encroaching most seriously on capacity.

[16] The cost apportionments used by the Federal Power Commission in its determination of reasonable rates for natural-gas pipeline companies, such as those which treat 50 per cent of the capacity costs as a demand cost and 50 per cent as a volumetric cost, would be utterly ridiculous if viewed as attempts at actual cost determinations. See, e.g., Matters of Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation, 11 F.P.C. 43 at 56 (1952). These apportionments can be justified, if at all, only on "fairness" or "value-of-service" considerations. Unfortunately, the Commission is bound by the provisions of the Natural Gas Act, which compel it to make arbitrary cost apportionments by restricting its rate-making jurisdiction to the sale of gas for resale, as distinct from sales made directly to industrial customers. On the general subject of gas-cost allocation, see Hans Nissel, "The Impact of Cost Allocations upon Future of the Natural Gas Industry," 66 *Public Utilities Fortnightly* 512–524 (1960); Larry Shomacher, "Is FPC Gas Cost Allocation Equitable?" 50 *Public Utilities Fortnightly* 680–688 (1952); Ott Eckstein, "Natural Gas and Patterns of Regulation," 36 *Harvard Business Review* 126–136 (1958); and Ralph Kirby Davidson's book cited in n. 10.

of the present inquiry is this distinction between joint production and merely common production of multiple products that a brief digression on the subject is in order.

Joint costs as distinguished from nonjoint common costs. Many years ago, the importance of the distinction between joint costs and nonjoint common costs was brought dramatically to the attention of the academic economists by a now famous debate on railroad rates between Professor Frank W. Taussig of Harvard University and Professor A. C. Pigou of Cambridge University.[17] Writing for the *Quarterly Journal of Economics*, Professor Taussig had taken issue with those earlier writers who had attributed the familiar railroad practice of "charging what the traffic will bear" ("value-of-service" rate making) to the possession of monopoly power. This practice, he contended, was quite in keeping with the recognized principles of joint-product price determination under conditions of strict competition. For even under competition, the relative prices of joint products are not based on relative costs of production. Instead, the price differentials are based on differences in relative demands for the respective products.

Classical examples of joint products are that of cotton fiber and cotton seed, and that of beef and hides. These sets of products are produced in more or less fixed proportions, with the result that much of the costly action needed in order to produce any given amount of the one (beef) will also go a long way toward the production of a corresponding amount of the other (hides). In competitive equilibrium, the prices of the joint products in the aggregate will equal their combined costs of production. But aside from the fact that each product will be priced at least at its separable costs of production (since otherwise its production would not be brought to completion), the respective prices will not be based on respective costs.[18] Instead, the sharing of the joint costs will depend entirely

[17] 27 *Quarterly Journal of Economics* 378–384, 535–538, 687–694 (1913). Professor Pigou amplified his argument in his *The Economics of Welfare*, 4th ed. (London, 1932), Chap. 18, "The Special Problem of Railway Rates." For a much cited later article on the subject, see Donald H. Wallace, "Joint and Overhead Cost and Railway Rate Policy," 48 *Quarterly Journal of Economics* 583–619 (1934).

[18] But the marginal cost of a by-product (in its extreme form) is determinate for reasons to be noted presently. In theory, it is possible to determine the marginal costs even of joint products if these products, so far from being producable only in fixed ratios, can feasibly be produced in varying proportions. The marginal cost of Product A is then the increase in total cost resulting from the output of an additional unit of this product, output of the other products being kept

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on the relative forces of demand. Hence, from the standpoint of cost analysis (though not from the standpoint of competitive price determination), a joint cost is an unallocable cost.

These classical principles of joint-product pricing were believed by Professor Taussig to be widely applicable to railroad rate making. Thus, he argued, passenger service and freight service might be considered joint products, as might also be lumber-transport service and wheat-transport service, etc. And the familiar practice under which the charges for the transport of high-valued commodities would be several times as high as charges for the transport of low-valued commodities was, therefore, in his opinion, quite consistent with competitive-price theory.

To this position Professor Pigou took sharp exception. While he conceded the existence of some examples of jointness in the production of different kinds of railroad service, he believed that these examples were very limited and that they did not include those cited as such by Professor Taussig. The most outstanding example, he said, was that of the forward and return haul of a railroad train. But passenger and freight service are not joint products, since the addition by a railroad of another passenger train or passenger car does not reduce the cost of adding freight trains or freight cars—quite the contrary, in fact, if the road is being operated close to the limit of its line-haul capacity. And the same statement applies to the transportation of different kinds of freight.

Pigou therefore concluded that the familiar "value-of-service" rate-making practices of the railroads belong, for the most part, in the category of monopolistic price discrimination and not in the category of competitive price determination under conditions of joint production. And on this main issue, Pigou's position rather than Taussig's has won general acceptance among the economists, although later rate experts have attributed to the multiple freight and passenger services of a typical railroad system more widespread elements of jointness (particularly, "time jointness") than Pigou was ready to concede.

constant. See the article "Cost" by Jacob Viner, in 4 *Encyclopaedia of the Social Sciences* 466–475 at 473. But such "fine" measurements of marginal cost are of limited usefulness in utility rate making, at least in its present stage of development. Moreover, "while cases of *absolutely* fixed proportions may be nonexistent, the proportion in which some products are produced may be variable only within very narrow limits and at great expense." National Bureau of Economic Research, Committee on Price Determination, *Cost Behavior and Price Policy* (New York, 1943), p. 177.

Capacity costs of utility services as a kind of joint costs. Electric and gas companies do not supply the particular examples of joint products and joint costs emphasized by Pigou with respect to transportation companies, namely, those of forward and backward haul. But they supply many examples of another, and even more important, kind of joint production, that of "time jointness." This factor of jointness is especially prominent for the electric utilities, since electricity cannot feasibly be stored for future use either by the producing company or by the consumer. Hence, electricity supplied at any given time is, in a significant sense, a different product from electricity supplied at any other time. And since, with exceptions that we may here overlook, an increase in plant capacity, if made for the purpose of enhancing the rate of output in any one period of time (say, between 5 P.M. and 10 P.M. during the winter, or between 10 A.M. and 4 P.M. during the summer), is also available for an enhancement in the rate of output at other times, services rendered at different times of day, week, or year are true joint products. This being the case, any apportionment of capacity costs, say, as between morning service and evening service, or as between winter service and summer service, or even as between all services rendered in the year 1959 and all services rendered in the year 1960, is a partly arbitrary apportionment from the standpoint of cost determination, however justified or convenient or rational it may be from the standpoint of reasonable rate determination.

In the determination of rate differentials, an "ideal" apportionment of capacity costs would be whatever apportionment would result in an approximation to a 100 per cent system load factor. Were it not for circumstances to be noted below, an "ideal" [19] structure of utility rates would solve the problem of cost imputation as between on-peak and off-peak service by preventing the

[19] Not *quite* ideal, however, since an electric utility company needs time to shut down its generating units for major repairs. In its 1957–1958 rate case before the Illinois Commerce Commission, the Commonwealth Edison Company stated that its seasonal load curve had now become so relatively level (due largely to its summer air-conditioning load) that it was planning its equipment overhauling "so that the sum of the following items remains constant for each month of the year: (1) the monthly peak load, (2) the capability of units scheduled to be out for overhauling in that month, and (3) limitations on capacity due to temperature of circulating water." Testimony of Murray Joslin, Vice President, Edison Exhibit 2, I.C.C. Case No. 44391. In consequence, "Edison's load pattern has materially changed, so that, currently, each month's peak load is as important as the annual system peak load in determining capacity requirements." Company's Reply Brief, p. 38.

problem from arising. A skillfully designed system of rate differentials would so distribute the burden of paying for capacity costs among consumers of services rendered at different periods of time, that the company's load valleys would be raised and its peaks would be lowered to the level of a plain. These differentials would be based on relative demands, on market-clearing forces rather than on cost analysis.

In actual practice, modern public utility rate making has gone a certain distance toward the realization of this ideal through the use of rates (such as those for interruptible power or for controlled water heating) which give to consumers a financial incentive to take their service at what is to them less convenient times of day, week, or season.[20] But it has not gone full way in this direction; nor can it be expected to do so, although further progress may be hoped for as a result, among other things, of further refinements in the art and science of rate making and in the promotion of new uses of service.

The most obvious restriction against valley-filling policies of differential rate making is that imposed by the limited potential demands for off-peak services—demands so limited that plant capacity would not be fully utilized even if off-peak rates were cut to bare incremental energy costs. This limitation may well apply to most electric systems during the dead of night, during holidays, and possibly even during seasons of the year intermediate between periods of maximum winter loads and maximum summer loads.

But even if an electric company were able to keep its plant running at full capacity through the entire year by cutting its charges for what would otherwise be off-peak service to bare energy costs, it might still not be warranted in doing so. For, as long as the company operates under conditions of declining unit costs, it *must* charge more than incremental or marginal costs for some of its services in order to cover its total costs. And off-peak service is likely to be among those services that can best stand a charge of this nature.

[20] A book on electric rate making in Switzerland states that, in that country, tariff policy has stressed its role as the most effective means of regularizing consumption. Newer uses of power have been so well developed that the December evening peak has become "only a minor peak." Pierre Devantéry, *Les Prix de l'électricité* (Lausanne, 1950), p. 105. But, as the more perspicacious writers on utility rates have long pointed out, "The practical improvements resulting from scientific rate systems have come not so much from limiting peak demands by penalizing them with heavy charges as from developing off-peak business by freeing it from the burden of overhead." John Maurice Clark, *The Economics of Overhead Costs* (Chicago, 1923), p. 328, citing examples and referring to Watkins, *Electrical Rates* (New York, 1921), p. 22. Bolton, taking a similar position, writes: "Of the two ways of improving system load factor, namely, by raising the individual load factor and by increasing the diversity, there can be little doubt that the second holds out far greater possibilities." *Costs and Tariffs in Electricity Supply*, p. 87.

At first thought one might assume that the price elasticity of demand for services at unpopular periods of time would always be high, with the result that these services should be offered for sale at "bargain" prices only slightly above their marginal costs. But this assumption would overlook the fact that the demand for certain amounts of off-peak service is a "convenience" demand—a demand that is highly inelastic over substantial but limited ranges of output. Hence, a company may well be justified in making no general concessions for nighttime service even though it may offer special, incentive rates for electricity to be used at night solely for the use of water heating.

The continued presence of peaks and valleys in public utility plant utilization gives qualified support to the system-peak responsibility principle of capacity-cost allocation. Regardless of the reason for the persistence of peaks and valleys in the load curves of utility systems, as long as they persist they raise the problem of cost imputation as between on-peak and off-peak service. This problem is soluble under familiar principles of joint-cost imputation subject to a number of simplifying assumptions. The reason why it is soluble, despite the general principle that joint costs are unallocable costs from the standpoint of cost analysis, is that we now have that "limiting case" of joint production in which one of two products, the off-peak service, is a by-product in the strictest sense of that term, whereas the other product, the peak-time service, is the main product. Under this condition, no longer does the increase in capacity costs incurred in order to increase the output of the main product have to its credit any useful accomplishment in enhancing the further output of the by-product. For the plant is already redundant with respect to the by-product. Hence, at the margin, the by-product is costless save for its separable costs (energy costs and possible customer costs), and the main product is chargeable with the entire incremental capacity costs. Whether or not the by-product should nevertheless be sold at a profit over incremental cost, in order to help cover the company's total revenue require-

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ments, is a problem of rate making, not a problem of cost analysis.

So far, then, the argument supports the system-peak responsibility formula of capacity-cost allocation. But the argument applies only to the allocation of *incremental* capacity cost—to the cost per kilowatt of enhancing the capacity rather than to the average cost per kilowatt of total capacity. To the extent to which this average cost either exceeds or falls short of incremental cost, it is unallocable on any principle of cost analysis. Unfortunately, this fact is ignored by fully distributed cost analysis of the public utility type.

Necessary use of stochastic methods by which to assign responsibility for capacity costs. The unqualified acceptance of a system-peak responsibility principle of capacity-cost apportionment (in so far as the average cost per kilowatt of capacity can be accepted as an approximation of incremental capacity cost) would imply that rates for off-peak service, if designed to cover only those costs allocable to this service, should include no allowance whatever for demand-related costs. And this statement would seem to apply to rates for services rendered at times that are only slightly off the system (or subsystem) peak, no less than to rates for services rendered at times when the system is operating at a mere fraction of its total capacity.

But the only costs that are directly relevant as measures of rates to be charged in the future are costs that will prevail in the future; and these costs must be estimated subject to the limitation that peaks and valleys in future loads are far from completely predictable. Hence utility rates, in so far as they are cost determined, must include charges for the *probability* that the service to which they apply will be taken at the time of the system peak—a probability which may be far lower if the service will be taken, say, at 3 A.M. daily than if it will be taken in a period which, during the past year or two, has been off system peak by only, say, 5 per cent. It follows that the sharp distinction between charges for completely and surely off-peak service and charges for completely and surely on-peak service will not serve all the purposes of rate making. Divisions of time into three or more periods, such as those observed in Europe, may be justified.[21]

[21] French rate experts have sanctioned a threefold division into "heures creuses," "heures pleines," and "l'époque de la pointe." Marcel Boiteux and Paul Stasi, "Sur la détermination des prix de revient de développement dans un système interconnecté de production-distribution," Report, Congrès de Rome, Sept., 1952, Union Internationale des Producteurs et Distributeurs d'Énergie Électrique. The British Technical Report (K/T 109), already cited in footnote 10, would meet this problem by an "improved method" for allocating demand-related costs to different classes of consumers under which (a) no account is taken of demand or consumption during "off-potential peak" periods; and (b) the allocation is to be based jointly on the consumption and the highest demand of the individual component loads within the potential-peak periods. This is a modified version of the "average-and-excess-demand method" (the "Greene Method"), already described.

So far as I am aware, the fully distributed cost apportionments of the type familiar to American gas and electric rate making do not attack directly this necessity of expressing costs, particularly capacity costs, in probabilistic terms. For they usually purport to reflect costs that have actually occurred in some past, test year, apportioned in the light of loads that have actually been experienced during that year. Hence, only to the extent to which history can be expected to repeat itself can these cost analyses be accepted as measures of those cost relationships which should receive weight in rate making to apply during future months or years.

In actual rate determinations, as distinct from special-purpose cost analyses which can make use of elaborate recording meters for testing purposes, the need to rely heavily on probability inferences, even of a pretty tenuous nature, in the design of the rate structure is greatly enhanced by the extreme crudeness of the accepted American devices for metering the individual consumers. Thus, most electric companies now use only watt-hour meters and no demand meters for residential and small commercial service; and even for large industrial power, the most frequently used demand meters are limited to the measurement of the customer's maximum demand during a given period of time (one month, one year, etc.), making no recorded distinction between those relatively harmless high individual loads which occur when the utility system has redundant capacity, and those very costly loads which coincide with system peak.

Handicapped by this absence of *recording* demand meters, and by the partial absence of *any* demand meters, a company must base its charges for different classes and different amounts of service on assumptions as to typical relationships between energy consumption and maximum loads, as well as between maximum loads and coincidence factors, that are sure to be wildly false in many cases. Thus, with the residential rate on a purely block-energy basis (subject only to a minimum monthly charge), any cost-based defense of lower charges for additional blocks of energy must rest on the assumption that the larger uses are increasingly off-peak uses—an assumption that was plausible in the earlier days when the main load was a lighting load but which is less tenable today.[22] The utility companies themselves are aware of this fact, and some of them have sought to minimize the deficiencies of noncompensatory terminal block-energy rates by the obviously crude device of a "stopper" provision, which prevents the consumer's *average* charge per kilowatt-hour from going below a certain minimum.

The great convenience and high popularity of residential rates based wholly on energy consumption (save for a modest minimum bill), combined with the economy of a simple and inexpensive watt-hour meter, probably justifies the continued use of this type of rate for traditional amounts of household consumption. But with the industry's drive toward the "fully electrified home," which uses electricity in large amounts for cooling in summer and for heating in winter, more elaborate metering devices will probably be called for. For this purpose the use of "time of day" and "time of season" differential energy rates, which has had more of a vogue in Europe than in America, may be well worth considering.[23] Here, use of service would still be metered in terms of kilowatt-hours rather than partly in terms of kilowatts of maximum demand. But the watt-hour meters may have two or three separate dials, by which to record the consumptions in different periods of time.

Special problems of capacity cost allocations to industrial power. Even if the allocation of capacity costs were not complicated by variations in the load curve of an electric power system during the day, week, and season of the year, the problem of rational allocation, and the related problem of rational rate making, would still be far from simple. For there would remain the problem of imputing to the services rendered during any given year proper shares

[22] A load-curve study of residential consumption by groups of customers using no electric ranges or water heaters is reported to have found that: "There is a slight general increase in annual load factor with increasing kwhr use, but this does not mean that increasing usage always improves annual load factor. Some added loads raise load factor, while others pull it down." *Electrical World*, Nov. 24, 1958, pp. 89–92, reporting on the findings of the Load Research Committee of the Association of Edison Illuminating Companies.

[23] In Chap. 10 of his book already cited in footnote 10, Davidson suggests this type of rate as preferable to the familiar Hopkinson-type rate. But among the objections to it is the danger that its sharp breaks will create surges in the loads imposed on a power station or on a distribution line.

of the capital costs incurred in the construction of plant and equipment designed to supply service for many years in advance. In order to be assignable to the services rendered during any one year, these construction costs are converted into terms of *annual* costs—costs composed of allowances for annual interest or "fair return" plus allowances for annual depreciation. But the conversion is necessarily largely arbitrary.[24] A cost analyst's statement, for example, that the total demand-related or capacity costs of an electric company have come to $12,500,000 (or $25 per kilowatt of capacity) during the past year does not report a cost that could have been saved if the plant had been shut down for this year; nor does it report a cost that was incurred merely and solely to supply the service required during this one year. Instead, it is an estimated or assumed *average* annual cost. And it would continue to be of an average character even if it were derived from an incremental cost of plant construction per kilowatt as against an average cost.

In order to illustrate the seriousness of this limitation of the typical cost imputation, let us assume that, because of a regular, five-year business cycle in the area served by the company, the plant capacity that is required in order to supply the demand for power during the two years of high prosperity will be unavoidably redundant during the remaining three years. What allocation or apportionment of annual capacity costs should be made under this assumption? The logic of the peak-responsibility method of capacity-cost imputation would require that all of this cost be imputed to the service rendered during the two prosperous years and that none of it should be assigned to the service of the other years—not even to the peak-time service of these years.

Indeed, just this kind of anticipatory cost imputation would be required if annual changes in system loads were regular and predictable. In fact, however, the changes are neither regular nor predictable, with the result that the cost analyst is pretty well limited to an attempt to report *annual* capacity costs based largely on such conventions as straight-line depreciation and on assumptions of uniformity in the annual allowances for "fair return."

In actual practice the serious consequences of these theoretical limitations imposed upon the cost analyst by the practical necessity

[24] On the arbitrary character of depreciation as an annual capital cost, see pp. 199–210, *supra*.

of converting capital costs of construction into annual capacity costs have been greatly reduced by the remarkable upward secular trend in the demand for many utility services including, notably, electric service. Hence even business depressions have not brought about many very long standing periods of plant redundancy—periods during which even the system peak falls for a long time far below plant capacity.

Yet the situation just mentioned—the arbitrary character of conversions of plant costs into annual costs or annual "rent values"—gives rise to serious problems on occasion, notably with respect to cost allocations or apportionments used in the support of rates for large-scale industrial power. Consider, for example, a large steel company with immediately prospective power requirements so large that the utility company, in order to supply these requirements, must add 50,000 kilowatts of otherwise unneeded capacity. Assume that the maximum load of this large customer coincides with system peak and that, in accord with the "peak-responsibility" principle, its annual charges for power during the following year will include 100 per cent of those interest charges, depreciation allowances, property taxes, etc., which constitute the annual costs of 50,000 kilowatts of capacity. Such charges might be supposed to constitute full indemnity for the cost to the utility of installing the additional capacity. And so they will if the steel company keeps on paying these charges, year after year, until the utility's investment in this capacity has been completely amortized.

But now let us suppose that, after the first year or two, the steel company cuts its demand for power to a maximum demand of 25,000 kilowatt-hours, or even shuts down its plant completely and moves to another location. In this event, the utility may find itself with a generating capacity in excess of its needs for several months or years to come, not to mention any investment in ancillary equipment that is no longer useful except for its possible salvage value. Should this possibility be actually experienced, the utility would not have been indemnified for the cost which it has incurred expressly in order to serve the particular customer and which it would not have incurred otherwise.

Public utility companies often seek to minimize these dangers of an unexpected drop in industrial-load requirements by the imposition of minimum, "billing demand" charges in excess of charges for

the maximum demands imposed upon them by an industrial customer during any given twelve-month period. But the industrial consumers are not fond of these charges, since they quite naturally desire to maintain the maximum freedom to cut their power costs if their volume of business declines. Moreover, except under some special contracts between the industrial user and the utility company, the obligation of the consumer to continue the payment of *any* charges for service will cease, or will have only a limited duration, if it is ready to abandon the taking of service altogether. In consequence, the rates of charge for service rendered to a gigantic user of power, regardless of the formula used in the determination of his annual demand charges, may well result in less than barely compensatory rates when measured in the light of hindsight. If based on advance estimates of "cost of service" these rates should therefore incorporate an appropriate allowance for the risk factor—for a risk factor well in excess of that which would be appropriate in an estimate of the cost of supplying the more stable, residential service.

The unpredictability of future demands for certain types of utility services presents another problem alike for cost analysis and for rate determination: namely, the problem of an unpredictable change in the system load curve. It is this complication, more than any other, which may account for the reluctance of most American cost analysts to apply a system-peak responsibility formula of capacity cost allocation.

Assume, for example, that at the present time, the utility's system peak occurs on winter evenings, when the residential load is at its peak and when the industrial power load is negligible. On this assumption, one may argue that all incremental capacity costs should be charged against residential service as a matter of cost analysis, even if "rate-making policy" should dictate a rate structure which relieves residential users of some of these costs and throws the burden onto other users. But assume that, at some unpredictable time in the near future, demand for industrial power (a demand, by the way, which is said to be inelastic except for voracious power-using industries such as aluminum producers) is very likely to outpace the demand for residential service and that, in consequence, the system peak may quickly change from a winter residential peak to a summer power peak. Under this assumption, the analyst may hesitate to impute to the residential users full responsibility for being currently on a system peak that may shift over to the industrial-power load in another year.

To be sure, some writers who defend strict peak-responsibility methods of cost allocation, for purposes both of cost finding and of actual rate making, would deny that any such hesitation is justified. Let both the analyst and the rate maker, they argue, consider only those cost relationships that will prevail in the immediate future, without undertaking the hopeless and useless task of guessing what these relationships may be in the next year or in the next ten years. And this argument has much force. But it also has those limitations that were noted in the preceding chapter as basic to all short-run marginal-cost determination: namely, in its failure to recognize the practical desirability of "dampers" on excessive rate fluctuations and hence the practical desirability of types of cost allocation which measure cost in terms of longer-run rather than of very short-run variables. Indeed, if rapid and unpredictable shifts in system load curves were held to require equally rapid shifts in those cost allocations that are used as a basis of rate making, then the whole methodology, and not merely the detailed technique, of functional cost analysis would need to be changed. For in that event, the relevant methodology would be one of short-run cost analysis, which treats all capacity costs as constant costs and which therefore bases any distinction between on-peak and off-peak use entirely on differential energy costs of base-load versus peak-load generators.

Reduced to practical terms of rate-making policy, the question here at issue is whether services which are now supplied on system peak, and which will almost surely continue to be so supplied for the very near future (regardless of any proposed changes in rates), should be charged today as if they were expected to remain on peak indefinitely; or whether services that are presently off peak should nevertheless be made to pay some share of those capacity costs for which they are likely to become responsible in the next several years. To this question neither the general theory of cost analysis nor the general theory of rate making can supply a conclusive answer. At least at the present stage in the development of both theories, action must therefore be based largely on "judgment."

This chapter began by raising the question what, if any, significance should be attached to fully distributed cost apportionments as

points of departure for public utility rate making. As a provisional answer, it suggested that the significance must lie in whatever claim can be made for the apportioned costs as indices, not of absolute costs but of relative differential or incremental or marginal costs. It then distinguished two types of full-cost apportionment, the double-step (or "railroad") type and the single-step (or "public utility") type, and proceeded to give major attention to the latter. A tentative opinion on the merits of this second type is now in order.

In my opinion, these merits are so dubious that they fully justify the skepticism with which utility cost analysis has been received by public utility companies and public service commissions. The basic deficiency of this analysis lies in its failure to distinguish between actual cost finding and mere cost apportionment—between those costs that can be imputed to specific classes or units of service by differential cost analysis and those other costs that should be deemed unallocable from the standpoint of cost determination even if they are somehow apportioned as a provisional step in rate determination. This failure seems to me critical.

Among the more specific deficiencies of the typical fully distributed cost analysis of the public utility type, three seem to me especially serious. In the first place, the capacity costs or demand-related costs are usually derived from book values of plant and equipment that reflect sunk costs in dollars of original investment, not costs that can be said to vary, except in a very indirect way, with present and future increases in plant capacity. In theory, this particular objection might be met by the use of appraised current values of the utility plant and equipment rather than by the use of book values. But if the appraised values were of no better quality than the "fair values" that are accepted as measure of the rate base in states applying a fair-value rule of rate making, their advantage over book values would be at least dubious.

In the second place, the cost analyst, faced with the necessity of apportioning all of his costs among three or four arbitrarily selected functional-cost categories, faces dilemmas such as that noted in the section of this chapter on customer costs. He is therefore bound to be impaled on one horn of a dilemma; and one may suspect that he chooses whatever impalement he believes to be less harmful in its consequences for sound rate making in view of noncost considerations.

And in the third place, most analysts, unwilling to follow the implications of joint-cost and by-product cost analysis in their treatment of demand-related costs, accept some compromise formula of apportionment, such as one which imputes capacity costs in proportion to noncoincidental maximum class demand. Here, too, one may suspect that the choice of the formula depends, not on principles of cost imputation but rather on types of apportionment which tend to justify whatever rate structure is advocated for non-cost reasons.

What has just been said, however, is by no means meant to imply that cost analysis is useless for rate-making purposes. On the contrary, it is utterly essential.[25] But the really important analyses are not those which attempt to apportion total capital and operating costs among the different classes or units of service. Instead, they are the analyses designed to disclose differential, or incremental, or marginal, or escapable costs—costs which are not ordinarily derivable from total costs and which cannot be added together so as to equal this total.[26]

It is these costs which should be the primary object of study of the utility cost analyst. Whether or not, in addition, some kind of apportionment of unallocable cost residues is also worth making, along the lines followed by the staff of the Interstate Commerce Commission, is a secondary question, on which I venture no present opinion.

In short, then, a thorough re-examination of the whole philosophy of modern public utility cost analysis has long been overdue. If this country were Great Britain, the appointment of a governmental commission to make such a re-examination would be called for.

[25] In 1948, Major H. J. Flagg, Executive Officer of the Board of Public Utility Commissioners of the State of New Jersey, wrote: "One may venture a guess that scarcely a dozen electric utilities in the United States have any but the vaguest notion of the relative costs—or productivity in terms of net earnings—of the several classifications of their business. Many utilities really do not know whether their industrial load under present rates is a desirable form of business or not." "What of the Industrial Load?", 130 *Electrical World*, Aug. 28, 1948, p. 82. But the traditional fully distributed cost apportionments warrant little more than "the vaguest notion." As far back as 1921, Dr. G. P. Watkins wrote: "Were cost accountants willing to (or expected to) deal with less than total expenditures, so far as they claim to obtain the actual cost of a particular good or service, their true service might be more clearly perceived and therefore greater." *Electrical Rates*, p. 118.

[26] Compare a similar view expressed by some recent cost accountants with respect to the cost determination of manufactured products. R. Lee Brummet, *Overhead Costing* (Ann Arbor, 1957), esp. Chap. 5.

XIX

DISCRIMINATION, DUE AND UNDUE

THE LEGAL RULE AGAINST UNDUE DISCRIMINATION

One of the most nearly universal obligations imposed by Federal and state laws alike on railroads and on other public utilities is the obligation to furnish service and to charge rates that will avoid "undue" or "unjust" discrimination among shippers or customers, actual or potential.[1] Early writers often cited this obligation as a unique attribute of a business "affected with a public interest." In later years the legal right of even a "private" business to practice discrimination in the pricing of commodities has been materially restricted in this country, notably so by the Robinson-Patman Act provisions of the antitrust laws.[2] But the latter restrictions are much more limited in scope, although more severe in their application within this scope, than are the antidiscrimination standards of the public utility laws.

The legal obligation of public utilities to avoid unduly discriminatory rate relationships is distinguished from the equally general obligation to charge rates, each of which is "just and reasonable" in itself.[3] Needless to say, these two basic mandates are related; and a commission's finding of undue discrimination between rates is likely to go hand in hand with a finding that at

[1] "The principal evil at which the Interstate Commerce Act was aimed was discrimination in its various manifestations." New York v. United States, 331 U.S. 284, 296 (1947), citing Louisville & Nashville R. Co. v. United States, 282 U.S. 740, 749–750 (1931).

[2] Corwin D. Edwards, *The Price Discrimination Law: A Review of Experience* (Washington, D.C., 1959); Herbert F. Taggart, *Cost Justification* (Ann Arbor, Mich. 1959); Frederick M. Rowe, "Cost Justification of Price Differentials under the Robinson-Patman Act," 59 *Columbia Law Review* 584–616 (1959).

[3] Interstate Commerce Commission v. Alabama Midland Railway Co., 168 U.S. 144, 172–173 (1897).

least one of these rates is also "unreasonable." But not necessarily so; for undue discrimination may be held to exist between two rates, neither of which would be found "unreasonable per se" —possibly because the one rate may lie near the bottom of a "zone of reasonableness" whereas the other may lie nearer the top. In this event, the remedy may take the form of an increase in the former rate, of a decrease in the latter, or of a mutual adjustment.[4]

Readers of the treatises and the case law on public utility and railroad rates will often come across bald statements to the effect that, in these regulated industries, the practice of rate discrimination is unlawful. In fact, however, such statements are grossly inaccurate. What the law forbids is merely "undue" or "unjust" discrimination.[5] To be sure, the statutes also declare to be "unjust" without qualification a certain overt type of discrimination that had a disgraceful early American history, particularly in railroad rate making: namely, so-called "personal discrimination," whereby different customers are charged different rates for substantially the same service, rendered under similar conditions.[6] But beyond this point the legislatures have been content with general language forbidding "undue or unreasonable" preferences or prejudices, leaving the task of interpretation to the commissions, subject of course to review by the appellate courts.[7]

In view of this situation, one might suppose that the commissions and courts, in their efforts to interpret and apply the rules

[4] In reclamation cases under the Interstate Commerce Act, a shipper must prove injury in order to recover compensation under the sole count of unjust discrimination, but not in order to recover for the payment of unreasonable rates.

[5] New York v. United States, 331 U.S. 284, 305 (1947), quoting United States v. Illinois Central Railroad Co., 263 U.S. 515, 521 (1924). The statutes use other terms, such as "unjust" or "undue" or "unreasonable" "preferences" or "advantages" or "prejudices." But the tribunals bring them all under the heading of unjust discrimination.

[6] The recent relaxation of the British rules against unjust discrimination in railway transport rates does not even except personal discrimination. See Alastair M. Milne, *The Economics of Inland Transport* (London, 1955), p. 52, referring to Sec. 21 of the Transport Act, 1953. See also J. P. Carter, "Personal Discrimination in Transportation: A European Technique," 47 *American Economic Review* 372–381 (1957).

[7] "Whether a preference or advantage or discrimination is undue or unreasonable or unjust is one of those questions of fact that have been confided by Congress to the judgment and discretion of the Commission." Manufacturers Railway Co. v. United States, 246 U.S. 457, 481 (1918). To the same effect, Swayne & Hoyt, Ltd. v. United States, 300 U.S. 297, 304 (1937), quoted in New York v. United States, 331 U.S. 284, 347 (1947).

against undue discrimination, would have taken pains to develop two clear-cut distinctions: first, a precise distinction between discriminatory and nondiscriminatory relationships among rates for different classes and quantities of service; and secondly, a definite set of standards by which to draw the line between those practices of discrimination that are forbidden and those other practices that are approved or, at least, tolerated. Indeed, precisely this double-jump method of arriving at a decision on the merits of a complaint of unjust discrimination is revealed or suggested in some of the rate cases—notably, in cases upholding the challenged rates despite an overt or implied admission of their discriminatory character.[8]

By and large, however, the tribunals have shared a popular feeling that "discrimination," as a practice of rate making, is an odious term. They have therefore been reluctant to characterize as "discriminatory" any rates which they find lawful. Approval is more likely to be expressed by a finding of "no undue discrimination," without any commitment as to whether discrimination of even a due type was found to exist.

This tendency to treat "undue discrimination" as if it were one word has been encouraged by the failure of the rate regulators to observe any single and definitive distinction between discriminatory and nondiscriminatory rate differentials. At times, the cases suggest a distinction similar to that drawn by economists, in deeming "discriminatory" any rate differential not based on a cost differential. But at other times "discrimination" has been used as a mere synonym for *any* kind of rate differentiation;[9] whereas at still other times it has become a convenient, shorthand

[8] See Manufacturers Railway Co. v. United States, 246 U.S. 457, 481–482 (1918), letting stand a rate impliedly discriminatory. In the 1930s several electric utility companies sought commission approval of an "objective rate plan" initiated by the Commonwealth and Southern Corporation as a means of shifting to a lower level of rates without temporary loss of revenue pending the development of an enhanced demand for the service. Enjoyment of the lower rates was temporarily limited to consumers whose monthly bills under these rates would not be less than their bills for the previous year. Not all commissions approved. But even those that did admitted in words or by implication that the plan was discriminatory. William F. Kennedy, *The Objective Rate Plan* (New York, 1937).

[9] This appears to be its use under the Robinson-Patman Act despite some cryptic language suggesting a distinction by Representative Utterbach in the Congressional hearings on the bill. Thus, the Act treats a cost difference as justification for discrimination, not as proving the absence of discrimination. See the references cited in footnote 2.

term for *undue* discrimination—for what has been called "discrimination in a legal sense." The Interstate Commerce Commission, for example, has never to my knowledge declared that "value-of-the-service" rate making, which it has always sanctioned, constitutes discrimination.[10] Yet this practice is regarded as the very essence of discriminatory monopoly pricing by the academic economists, even by those economists who defend it as in the public interest.

In view of this confusion of language, something is to be said for the proposal to drop the word as a tool of public utility rate making or else to let it refer to *any* difference between rates of charge for physically similar types of service. But even if this proposal should win general acceptance, there would still be a need to understand the significance of the distinction that economists have attempted to draw, although with only partial success, between discriminatory and nondiscriminatory rate relationships. In the remainder of this chapter, we shall first discuss the nature of the distinction and shall then turn to the problem of setting practical limits between "due" and "undue" forms and degrees of discrimination.

ECONOMIC MEANING OF PRICE OR RATE DISCRIMINATION

In the literature of economics, one of the cardinal attributes of prices under assumed conditions of "perfect competition" is that of a uniform price for any one product at any given time and place. This uniformity precludes not only the price higgling that still characterizes many European markets but also the systematic practice of price differentiation designed to impose different charges on different groups of persons depending on differences in their capacity and willingness to pay. A purely competitive price is the same to the rich and the poor, to the powerful and the powerless, to the person who finds the product barely worth buying and to the person who would pay ten times the prevailing price rather than go without.

[10] For a possible exception, see the New York Harbor Case, 47 I.C.C. 643, 736 (1917). Utility representatives tend to deny that "value-of-service" pricing is "discriminatory." See, e.g., L. R. Nash, *The Economics of Public Utilities* (New York, 1931), p. 458. An opinion in a telephone rate case by the New Jersey Commission holds that *failure* to recognize relative "value-of-service" in exchange areas of different sizes would constitute (unjust) "discrimination." Re West Jersey Telephone Co., 91 PUR NS 33, 41 (1951).

This pressure, exercised on all sellers in a strictly competitive market, to sell any given product at a uniform price may be imposed more or less effectively even upon a monopolist unless he can divide the market for his product so as to prevent ready transfer among buyers. Otherwise, if the monopolist should attempt to discriminate, say, by selling lead pencils to general customers at 10¢ each while selling them to school children at only 5¢, there might arise a resale market beyond the seller's control, in which adults could buy pencils directly or indirectly from school children at less than 10¢.

But with many commodities and, particularly, with many personal services, transfer of the product among buyers is either impossible or inconvenient. Here the monopolist has the power, if he so chooses, to maintain substantial price differentials among different consumers or consumer groups. Not only does he possess this power; he will find it profitable to exercise it if, without too much expense and popular ill will, he can divide his customers into those who, at a uniform price, would have a relatively high elasticity of demand for the product, and into those who, at this same price, would have a relatively low elasticity. The profitability of the practice lies in the monopolist's ability to enjoy what would otherwise be the inconsistent advantage of doing a relatively large volume of business at a low unit rate of profits, and of doing a relatively small volume at a high rate. And public utilities, save when constrained by regulation or by public opinion, are in an especially favorable position to profit by this practice because of their monopoly status, their ability to prevent or restrict transfer of their services among consumers, and their tendency to operate at unit costs which decline as their rates of output increase.

If the term "price discrimination" were to be limited to the narrow meaning[11] given to it in the preceding paragraphs, it

[11] The outstanding modern analysis of price discrimination is by Mrs. Joan Robinson, *The Economics of Imperfect Competition* (London, 1948), Chaps. 15 and 16. She uses the term in the narrow sense, to refer to "the act of selling the same article, produced under a single control, at different prices to different buyers." P. 179. For the classical treatment of discrimination in its welfare aspects, see A. C. Pigou, *The Economics of Welfare*, 4th ed. (London, 1932), Chap. 17. Though supposedly impossible under *perfect* competition (by very definition of this latter term), price discrimination is a recognized practice under the competition of the actual market place. See, e.g., Eli W. Clemens, "Price Discrimination and the Multiple-Product

would apply only to the type of practice forbidden without qualification by the various public utility statutes and by Section 2 of the Interstate Commerce Act, namely, to the practice of charging different rates to different customers for substantially the same product. Hence, a broader definition is needed in order to cover "discriminatory" rate differentials for different types and quantities of service. But attempts by economists to supply this extended definition have run into difficulty and have never attained complete success.

Among economists there would probably be general agreement that the practice of exacting different charges for different classes of service rendered at the same marginal costs constitutes discrimination, and equally general agreement that failure to impose higher charges for services rendered at markedly higher marginal costs is also discriminatory. But if Service A (say, low-tension electric power) costs more to supply than Service B (say, high-tension power), just what price relationship between the two services can then qualify as nondiscriminatory? Here, two different answers have been suggested: the one that the rates must be proportional to marginal costs; the other that the differences in rates must be equal to the differences in these costs.

Of course, if all rates were to be set precisely at marginal costs, both of these suggested conditions of nondiscriminatory relationship would be met.[12] And this is the situation supposed to prevail under perfect competition, since prices in competitive equilibrium are equal both to average and to marginal costs. But particularly with public utilities, which must often charge rates

Firm," 19 *Review of Economic Studies* 1–11 (1950–1951), reprinted with alterations in Richard B. Heflebower and George Stocking, ed., *Readings in Industrial Organization and Public Policy* (New York, 1958). The history of railroad and public utility rate making would give strong support to the thesis that the condition most conducive to discrimination is not that of thoroughgoing monopoly but rather that of lopsided competition. See G. P. Watkins, *Electrical Rates* (New York, 1921), p. 199.

[12] However, there would remain the question whether the relevant marginal cost is of a short-run or a long-run variety. If one were to accept the price relationships of perfect competition as setting the norm of nondiscriminatory prices, the short-run cost would be the more nearly relevant, although this cost would itself tend to come into accord with long-run cost under conditions of competition. See pp. 331–332 of Chap. XVII. But in the regulation of public utility rates, the "practical" identification of nondiscriminatory rates with rates properly aligned with long-run marginal costs may be justified for reasons set forth in Chap. XVII and again to be discussed in Chap. XX.

substantially higher even than long-run marginal costs in order to cover their revenue requirements, the two answers just suggested are in conflict, and the choice between them presents a dilemma. Let us consider each choice in turn.

Discriminatory rates sometimes defined as rates not proportional to marginal cost. Under the proportionality definition, which has been favored by some economists,[13] the rates of a public utility company would be said to be nondiscriminatory if all of them were to exceed the marginal costs of supplying the respective services by some uniform percentage—say, by a 20 per cent minimum necessary to make total receipts cover the company's total revenue requirements. These hypothetical rates might then be used as points of departure by reference to which a rate maker might calculate whatever degrees and types of discrimination are deemed necessary or desirable on "value-of-the-service" principles of rate making.

As a practical, first-approximation standard of nondiscriminatory internal rate relationships, this standard is probably more widely applicable than any proposed alternative. Rates based thereon would go a considerable distance toward accomplishing the economic objectives of a "cost-price" system of rate making. For they would impose equal charges for services of equal costs, and higher charges for services of higher costs. And they would avoid the most significant *form* of discrimination, namely, value-of-service rate making.

Nevertheless, the proportionality definition has obvious deficiencies. For it would embrace some rate relationships that have the same distorting influences in affecting consumer choice among alternative services which economists associate with the practice of discrimination. The nature of these distortions will be noted in the following paragraphs.

[13] For example, by George J. Stigler, *The Theory of Price*, rev. ed. (New York, 1952), pp. 214–215; Tibor Scitovsky, *Welfare and Competition* (Chicago, 1951), p. 410; Ralph K. Davidson, *Price Discrimination in Selling Gas and Electricity* (Baltimore, 1955), p. 23 (but compare his different implied definition on p. 22); A. M. Henderson, "Prices and Profits in State Enterprise," 16 *Review of Economic Studies* 13–24, 23 (1948–1949). The proportionality definition is clearly the better choice with respect to the price relationship between services for which the demand is not interdependent. It is deficient when applied to complementary products (such as phonographs and phonograph records) and to substitute products (such as beef and mutton).

Alternative definition of discriminatory rates: rate differentials not equal to cost differentials. One of the major objectives of sound public utility and railroad rate-making policy is that of bringing rates for substitute services into proper relationship, so that consumers or shippers will not be led to make an economically "distortionate" choice between alternatives. This objective requires that equally costly services be sold at the same rates of charge. And it would also seem to require that when services are substituted for each other in fixed physical ratios (one coach trip versus one Pullman ride between New York and Chicago; one multi-party telephone versus one single-party telephone; one supply of off-peak electric power versus an equal supply of on-peak power; etc.), the differences in charges should be equal to the differences in costs. But as long as rates, while higher than marginal costs, are made proportional thereto, the price differentials will exceed the cost differences—an excess which may lead many consumers to make an "uneconomic" choice of the less costly alternative.

Recognition of this situation has led some writers to reject the proportionality definition of nondiscriminatory rates in favor of a cost-differential definition.[14] This point of view seems to have been accepted by the Cost Section of the staff of the Interstate Commerce Commission as a reason for its refusal to apportion railroad cost residues (excesses of total costs of railroad operation over estimated long-run out-of-pocket costs of specific classes of traffic) among the units of traffic (tons and ton-miles) in fixed percentages of the allocated out-of-pocket costs.[15]

[14] For example, Donald H. Wallace, "Joint and Overhead Cost and Railway Rate Policy," 48 *Quarterly Journal of Economics* 583–619 (1934); David G. Tyndall, "The Relative Merits of Average Cost Pricing, Marginal Cost Pricing, and Price Discrimination," 65 *Quarterly Journal of Economics* 342–372 at 343 (1951); Philip Locklin, *The Economics of Transportation*, 4th ed. (Homewood, Ill., 1954), p. 142.

[15] See the references to the Interstate Commerce Commission cost apportionments in footnote 4 of Chap. XVIII. In earlier days, before the *Class Rate Investigation*, Docket 28,300, the Cost Finding Section of the Commission's staff prorated constant costs in a fixed percentage of variable costs. But it now adds a uniform, pro rata allowance for "burden" (constant costs) to each ton (for terminal costs) and ton-mile (for line-haul costs). As a result, "it limits the differences in the fully distributed costs for any two shipments in the commodities hauled a given distance to the differences in the out-of-pocket costs, and it is the latter expenses which reflect those transportation conditions which have a bearing on costs." Samuel A. Towne, Chief, Cost Division, *I.C.C. Practitioners' Journal*, May, 1954, p. 702.

Unfortunately, however, the cost-difference standard of nondiscriminatory rate relationship can be given only a very limited application and is quite inapplicable to the general design of a rate structure. For the different services of any railroad or public utility company are not limited to substitutions in pairs or in any fixed physical ratios. Instead, they offer many different types of substitutions and at ratios that depend in part on relative rates of charge. This being the case, any attempt to make differences in rates for all classes and quantities of service equate with differences in costs between *some* alternatives (such as alternatives between more or less of the same kind of service) would frustrate attempts to accomplish the same objective with respect to *other* alternatives (such as alternatives between equal quantities of different grades of service). Moreover, such an attempt would throw an impossibly heavy burden of residue costs on the purchasers of the smaller quantities and on the less expensive grades of service.

Complete avoidance of discrimination is therefore impossible when rates in the aggregate are above marginal costs. Impressed with the difficulties just suggested, some of the more recent writers on price or rate theory have concluded that, as long as the prices charged by any given enterprise must exceed marginal costs, complete avoidance of discriminatory relationships among these prices is simply impossible.[16] And this is the view accepted in the present book. A certain amount of discrimination, of internal price distortion, would therefore be unavoidable even for an enterprise which would prefer to avoid it and which has neither the need nor the desire to practice value-of-service rate making as a means of maximizing profits.

In view of this somewhat frustrating situation, and not merely because some practices of discrimination are positively desirable, the law is indeed well advised to forbid only those discriminations which are "undue." This means that the attempt should be made to outlaw or minimize those price relationships which have a *serious* distortion effect on relative use of services, even at the expense of accepting other discriminatory price relationships which are less likely to have such an effect. In electric utility rate

[16] Joel Dean, *Managerial Economics* (New York, 1951), pp. 504–512; William Vickrey, "Some Implications of Marginal Cost Pricing for Public Utilities," 45 *American Economic Review, Proceedings* 605–620 (May, 1955).

making, for example, lower rates for industrial power than for residential service, even if not based on comparable cost differentials, will hardly lead consumers to reduce their residential consumption in favor of an increase in their industrial power load. The two services are noncompetitive, and there is no good reason to assume the existence of a high "cross-elasticity" of demand for them.[17] On the other hand, off-peak and on-peak electric services are, *to some extent,* alternative products. Hence, the relationship between on-peak and off-peak rates for similar classes of service may be a matter of special importance with respect to its substitution effects.

VALUE-OF-SERVICE RATE DISCRIMINATION

Most discussions of the merits and demerits of rate discrimination are not concerned primarily with those discriminatory relationships which are simply unavoidable under any full-cost system of rate making. Instead, they are concerned with that deliberate policy of rate differentiation known as "value-of-service" rate making or, in railroad parlance, as the practice of charging "what the traffic will bear." Here, the apportionment of the burden of covering any excess in total costs over marginal costs (or "out-of-pocket" costs) is deliberately "biased" so as to impose on the services in relatively inelastic demand (services of high "value" in popular speech) higher surcharges, over and above marginal costs, than would be imposed by *any* rule of apportionment based exclusively on cost relationships.

The most familiar use of the value-of-service principle is found in railroad rate making, where higher rates are charged for the shipment of goods of higher value, the rate differentials being far greater than those which could be justified by any cost differentials.[18] Among the nontransport utilities, this principle is perhaps

[17] "Cross-elasticity of demand" refers to the tendency of an increase (or decrease) in the price of any given product to result in an increase (or decrease) in the demand for a substitute product. Thus, an increase in the price of gas may lead to an increase in the demand for electricity, absent any change in the price of the latter product.

[18] See the study on *Value of Service* dated Nov., 1959, prepared by the staff of the Interstate Commerce Commission. The readiness of the Commission to accept the value of the shipped commodity as an index of the value of the transportation service has been a subject of much comment and of some speculation as to *rationale.* Certainly the correlation between the two "values" must be poor. It seems likely that the Commission has been aware of this poor correlation but has tended to support a commodity-value standard of rate classification on its own

most openly avowed by the telephone companies, which adduce it as the major defense of their practice of charging for local service higher rates in larger cities than in smaller communities.[19] But electric and gas rate making is also admittedly under the influence of the principle, although the lack of any really satisfactory differential-cost analysis in these industries precludes quantitative statements as to the force of this influence in the determination of class rates and block rates.

From the standpoint of a corporate monopoly with the assumed objective of profit maximizing, the case for this type of discrimination is obvious, although the most profitable extent of the practice is by no means easily determined. Even from the standpoint of the public interest, the argument in its favor is clear enough under the assumption that some discrimination is utterly essential in order to meet revenue requirements.

But the more interesting and important question concerns the desirability of value-of-service rate making even for an enterprise which could cover its total costs of production, including a capital-attracting rate of return, by basing its rates entirely on cost differentials. Here the advantage must lie in the resort to discrimination as a means of encouraging the maximum economic use of a company's services consistent with the so-called "full-cost" requirement. For this purpose, the rate structure imposes the higher surcharges, over and above marginal costs, on classes and quantities of service for which demand is relatively unresponsive to price changes.

Ideally, this type of discrimination might permit a company to cover its total costs without repressing the demand for any service for which consumers would be ready to pay at least marginal costs—to pay what rate makers have called "compensatory" rates. In practice, this ideal is unattainable; for the only feasible types of discrimination are crude types, which must necessarily

merits and not merely as a presumptive measure of service value. But the recent competition of motor, water, and air transport has hit this standard hard, and its days as a major basis of railroad rate structure may be numbered. In an unpublished paper, my colleague Professor Joel Dean suggests that the imposition of higher charges for more valuable shipments (over and above insurance-cost differentials) is particularly bad for the railroads since the trucks, being faster on delivery, have a special quality-of-service advantage in the transportation of high-valued commodities.

[19] See pp. 83–84, *supra.*

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impose relatively high charges for classes and quantities of service, for *portions* of which the demand is highly elastic.[20] But discrimination need not be "ideal" in this respect in order to be less repressive of economical demand than would a rate structure based entirely on cost relationships.

Value-of-service rate discrimination versus joint-product pricing. Before turning to the question what restrictions should be imposed upon a utility company's freedom to practice rate discrimination of a value-of-service character, we must first emphasize the distinction between this practice and the practice of joint-product pricing. This distinction was drawn in the previous chapter with special reference to railroad rate making. But it is so often ignored, despite its high importance for rate theory, that a further reference to it is in order.

Unlike price discrimination, joint-product price differentiation is a phenomenon characteristic of the strictest forms of competition. In one respect the two practices are akin, in that the price relationships of the joint products—cotton fiber and cotton seed, hides and meat, superior cuts of meat and inferior cuts, etc.—depend on demand relationships and are not determined solely by cost relationships.[21] But they differ in that the joint-product relationships are designed to "clear the markets" for the joint products in view of largely fixed ratios of feasible output. Thus, the different charges for the different cuts of meat will adjust relative demands so that no meat is wasted, not even the inferior cuts.

On the other hand, value-of-service rate discrimination, instead of adapting relative rates to unavoidable relative scarcities of the different types of service, curtails the output of the service in less elastic demand without bringing this output into an optimum balance with the available output of the service in more elastic demand. This procedure may be justified for reasons already suggested. But the justification must lie in the choice of the lesser evil—in the view that the resulting repression in the demand for

[20] In Pigou's terms, this amounts to the statement that the only feasible discrimination is discrimination of the "third degree." *The Economics of Welfare*, Chap. 17. Perhaps the closest practical approach to completely nonrepressive forms of discrimination in public utility rates may be found in skillfully designed block rate making, which allow lower rates to a given consumer for successive blocks of service. See Davidson, *Price Discrimination in Selling Gas and Electricity*, Chap. 2.

[21] For a qualification, see footnote 18 of Chap. XVIII.

the service discriminated against, while unfortunate, will be less unfortunate than the repression in the demands for one or both services that would result if both were priced above marginal cost but without reference to "what the traffic will bear."

Thus, if railroad traffic is not evenly balanced between forward and backward hauls, the principle of joint-product pricing requires the imposition of differential charges in favor of the lighter traffic. But this differential is not discriminatory at all; on the contrary, uniform pricing would be discriminatory even though commissions and courts have not often so regarded it.[22] Or again, if an electric plant is operating near its full capacity, the imposition of higher charges for on-peak than for off-peak service would actually be required in order to avoid discrimination.

I stress this point in the present chapter because many of the practices of rate differentiation which are called discriminatory in popular parlance are nondiscriminatory in an economic sense. By the same token, many of the rate uniformities widely accepted in current public utility regulation, such as the use of "blanket" electric rates throughout large areas within which costs of service differ markedly, are discriminatory from the viewpoint of an economist. Again we come back to the point that the law, so far from completely forbidding, actually approves or even requires discrimination of many types and degrees.[23]

THE PROBLEM OF DISTINGUISHING BETWEEN DESIRABLE AND UNDESIRABLE RATE DISCRIMINATION

Even if the sole object of public utility rate making were assumed to be that of maximizing the profits of a given company,

[22] On the tendency of the Interstate Commerce Commission to forbid or restrict the quotation of low, return-haul rates, see Marvin L. Fair and Ernest W. Williams, *The Economics of Transportation*, rev. ed. (New York, 1959), pp. 600–601. At times the Commission has even required that the rates be lower in the direction of the greater volume of traffic. I. L. Sharfman, *The Interstate Commerce Commission*, Vol. III B (New York, 1936), pp. 570–571.

[23] Compare the statement by M. A. Adelman that the Robinson-Patman Act, although called an antidiscrimination law, consistently enforces discrimination in that it declines to go beyond severe limits in validating price differences justified by cost differences. For it (a) expressly forbids discounts to buyers who avoid brokerage costs, (b) permits the Federal Trade Commission to set maximum quantities for discounts regardless of savings in cost, and (c) imposes what Adelman regards as a hopeless burden of proof of cost differentials. "The Consistency of the Robinson-Patman Act," 6 *Stanford Law Review* 1–22 (1953).

the question how far it would pay this company to "bias" its relative rates of charge by rate differentiation of a value-of-service character would be a question of great practical difficulty. To be sure writers on the theory of monopoly pricing have offered formal answers based on simplified assumptions. But their direct application would require a knowledge of demand and cost functions which rate makers simply do not and cannot possess.[24]

Even more formidable are the problems raised by the question to what extent, and subject to what restrictions, the practice of this kind of discrimination is in the public interest. Here too, theoretical answers have been offered by recent economists.[25] They take the form of a statement of conditions for "optimum rates subject to a budgetary constraint"—subject, for example, to the requirement that the rates of any one company must yield total revenues equal to total operating expenses plus a "fair return" on capital investment. But just as with the problem of price determination for the purpose of securing maximum profits, so with this distinct though related problem, their application would call for unattainable information about elasticities of demand and supply. Moreover, they depend for their validity on the acceptance of highly artificial standards of social welfare. At the present stage of their formulation, they can hardly serve as practical guides to the rate maker or rate regulator in his attempt to draw

[24] The problem of estimating price elasticity of demand is especially intractable. Professor Ernest Williams writes: "Unfortunately, little is known in a quantitative way about the elasticity of demand for the railroad freight service. Since it is a derived demand its analysis is fraught with the utmost difficulty." "Railroad Rate Levels and Earning Power in an Era of Competitive Transport," 25 *Land Economics* 405–413 at 409 (1949). On the elasticity of demand for electricity, see D. J. Bolton, *Electrical Engineering Economics*, Vol. 2: *Costs and Tariffs in Electricity Supply*, 2d ed. (London, 1951), Chap. 1; Hubert F. Havlik, *Service Charges in Gas and Electric Rates* (New York, 1938), Appendix C, "The Relationship between Rates and Consumption"; Samuel Ferguson, "Do Rate Reductions 'Per Se' Bring Increased Use?", *Public Utility Papers* (Hartford, Conn., 1947), II, 757–778; H. S. Houthakker, "Electricity Tariffs in Theory and Practice," 61 *Economic Journal* 1–25 (1951).

[25] Marcus Fleming, "Optimal Production with Fixed Profits," 20 N.S. *Economica* 215–236 (Aug., 1953); Marcel Boiteux, "Sur la gestion des mônopoles publics astreints à l'équilibre budgétaire," 24 *Econometrica* 22–40 (1956). For a closely related problem in taxation, see F. P. A. Ramsey, "A Contribution to the Theory of Taxation," 37 *Economic Journal* 47–61 (1927). The general conclusion, based on simplified assumptions including assumed independent demands for the various services, is that rates should be proportional to the demand elasticities of the various services at these rates. Applied to utility rates, Ramsey's article implies that the surcharges above marginal costs should diminish in the same proportion as the demand for each service. I take it that these two propositions are essentially the same.

lines between "due" and "undue" forms and degrees of price discrimination.

How, then, should these lines be drawn in practice? Much of the entire literature on railroad rates might be viewed as a discussion of this extremely complex question.[26] But all that will be attempted here is a suggestion of a number of partial, tentative answers applicable even to the nontransport utilities.

First, the legitimate role of the value-of-the-service principle is a role limited in its application to a public utility company which must charge rates in excess of marginal costs in order to meet revenue requirements. Hence, this principle has its most clear-cut defense for companies with chronically redundant plants, as is the case with most American railroads.[27]

Secondly, as a wise, practical rule, value-of-service rate differentials should not often be permitted unless they can be expected to result in lower rates even for those consumers who are discriminated against. The possibility of such a happy result was illustrated in the concluding section of Chapter XVI. It arises when special, low rates are granted for types or quantities of service which could not otherwise be attracted but which will make some contribution to total revenue requirements over and above mere incremental costs. True, utility rate theory offers no positive proof that discrimination should stop at the point just suggested. Conceivably, the public interest might be served by a decrease in the rates for services in highly elastic demand even at the expense of necessary increases in the rates for services in inelastic demand. But considerations of income-distributive fairness would be likely to weigh against any such arrangement.

Thirdly, permission to discriminate in favor of some uses of service that could not otherwise be attracted should seldom be granted in the absence of good evidence that the favored rates will

[26] For a review of the case law on unjust discrimination, see Isaac B. Lake, *Discrimination by Railroads and Other Public Utilities* (Raleigh, N.C., 1947).

[27] The principle also applies to companies in a position to enjoy long-run economies of scale. Telephone companies are not supposed to be in this position, at least not if the unit of output is taken to be a telephone station rather than a telephone message. This fact has led some writers to question the validity of the value-of-service principle as applied to telephony. But the telephone industry rests its defense on what amounts to a "social" theory of reasonable rates—a theory based on the importance to the community of individual access to the telephone. See pp. 114–115, *supra*.

cover, not just those short-run incremental costs due to a temporary redundancy of plant capacity, but rather those "long-run" incremental costs (including incremental capital costs) which can be expected to persist for the indefinite future. Otherwise, there arises the danger, noted in Chapter XVII, that the favored consumers will secure a kind of vested interest in the maintenance of their preferential rate relationships even after the economic excuse for this preference has ceased to be valid.[28]

Fourthly, even if a utility company, by the skillful practice of discrimination, could and would thereby reduce *all* of its rates, including the rates which it charges to those consumers who are discriminated against, the practice should nevertheless be forbidden if it would seriously prejudice the competitive business relationships between these consumers and those other consumers who would receive a preference. This maxim, which is based on a recognition of the high importance of rules of "fair competition," applies with special force to transportation rates. But it also applies to nontransport utility rate making with respect to relative charges to competitive businesses for larger and smaller amounts of electric, gas, telephone, and water-supply services.

At least in rate regulation under the Interstate Commerce Act, a finding of unlawful discrimination among rates is said to be contingent on a finding of competitive injury, actual or potential, except for the absolute statutory taboo of Section 2 against charges of different rates to different persons for a "like and contemporaneous service in the transportation of a like kind of traffic under substantially similar circumstances and conditions." [29] I am not sure whether a similar statement would apply to the laws restricting the practice of discrimination by the utilities. But no

[28] On vested-interest claims against rate increases, see the Interstate Commerce Commission staff report on *Value of Service,* Nov., 1959; Antioch Milling Co. v. Public Service Company of Northern Illinois, 4 Ill., 2d 200, 123 N.E. 2d 301 (1954), citing other cases; Southern Pacific Co. v. Interstate Commerce Commission, 219 U.S. 433 (1911). It is my distinct impression that vested-interest arguments have carried much more weight with commissions than with the appellate courts.

[29] And except for long- and short-haul discrimination. See I. L. Sharfman, *The Interstate Commerce Commission,* Vol. III B (New York, 1939), p. 529. But Sharfman notes that on occasion, the Commission has suggested that a rate may be "unduly preferential" merely because it is so low as to throw an unjust burden on the entire complex of other traffic. And see New York v. United States, 331 U.S. 284, 308 (1947) for an indication that the assertion cited in the text should at least be qualified.

one can doubt that the competitive-injury injustice of "unjust discrimination" is the injury that receives major emphasis by courts and commissions.

In the railroad rate cases, which offer the bulk of the cases on undue discrimination under public utility law, the decisions concerned with fair versus unfair competitive relationships among rates for different types of traffic and for different points of origin and destination seem confusing and inconsistent. A discussion of these decisions is a major task of the treatises on transportation rates. Here let me note merely that the Interstate Commerce Commission has only occasionally permitted railroads to quote lower rates for freight shipments in trainload lots than for single carload shipments despite substantial economies in the former type of traffic.[30] This means that the Commission, probably desiring to make some limited use of railroad rates as a positive device by which to discourage the growth of dangerously large-scale business, has actually made mandatory a certain degree of discrimination in favor of the smaller shipper. The wisdom or lack of wisdom of this rule, which is similar to a well-known provision of the Robinson-Patman Act,[31] is a question beyond the realm of utility rate theory.

Enough has been said in this very elementary chapter on the character, the advantages, and the abuses of rate discrimination to suggest reasons why the law of rate making, no less than the literature on utility rate theory, recognizes alike the justification for the practice and the need for its strict limitation. To the economist, this practice is viewed as a means of minimizing the harmful effect that would otherwise result from the acceptance of a so-called full-cost standard of rate making. But the harm can only be reduced thereby, not completely avoided. In the next and final chapter, we shall therefore turn to a proposed alternative system of rate making designed in principle to outlaw, and not merely to restrict, discrimination.

[30] See American Bound Bale Press Co. v. A.T. & S.F. Ry. Co., 32 I.C.C. 458, 463–464 (1914); Sharfman, *The Interstate Commerce Commission,* Vol. III B, p. 514.

[31] The provision authorizing the Federal Trade Commission to place limits on quantity sales entitled to further discounts by virtue of cost savings.

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THE PHILOSOPHY OF MARGINAL-COST PRICING

With only minor exaggeration, this entire book may be viewed as an attempt to play variations on a main theme first expressly set forth in Chapter III, "The Role of Public Utility Rates." This theme runs to the effect that utility rates, like other prices, are designed to perform multiple functions as instruments of economic control. To a high degree, these functions can be performed in harmony; necessarily so, indeed, since they are partly complementary. But the harmony is far from complete, for the most efficient performance of any one function would require the acceptance of a system of rates not also best designed to perform any of the others. In consequence, one of the most frustrating problems of rate theory and of practical rate making is that of suggesting and applying principles of workable compromise.

Among these conflicts of rate-making objectives, one of the most serious is that between the usually accepted principle that the rates of any public utility, in the aggregate, should cover its total costs of service, including fixed charges or a "fair return," and the also widely approved principle that specific rates should be based on the costs of specific amounts and types of service. For reasons stated in Chapter XVI, these two goals of rate-making policy are incompatible except under a somewhat rare coincidence in corporate operation and finance. In the absence of such a coincidence, any attempt to attain them both completely would be as hopeless as would be an attempt to draw a square circle.

How has rate-making practice undertaken to face this dilemma? In the main, except when circumstances have made the gap be-

tween the two objectives too wide to jump, it has done so by a somewhat qualified grant of priority to the first goal—that of a level of rates adequate for financial self-sufficiency. Even here, cost-of-service criteria of specific rates and rate relationships have received "due consideration." But these criteria have been relegated to a subordinate position, yielding precedence to the total-cost standard partly through overt deviations of a value-of-service nature, partly through loose "interpretations" of cost of service in terms of ill-defined and arbitrary "fully distributed" costs rather than in terms of differential or incremental or marginal costs.

Accepting, at least for the purpose of discussion, the traditional priority of the full-cost-coverage goal of rate-making policy, the four preceding chapters have considered methods of rate differentiation designed to permit the attainment of this goal with the least harmful departures from the principle of specific cost pricing. These methods include the limited but substantial resort to price discrimination. But while, under most conditions, their skillful application may bring about a reasonable degree of harmony between the two above-noted criteria of a sound rate structure, the results are bound to be far from ideal. Indeed, in some situations, including those now faced by the American railroads and, possibly, by the natural-gas industry, the results may become almost intolerable.

Impressed with both the theoretical and practical difficulties of any attempt to secure a sound structure of individual rates subject to the constraint that rates as a whole must cover costs as a whole, one important group of modern economists has proposed to seek riddance from this constraint. Let all rates be set at marginal costs. But if the resulting revenues should fall short of meeting total financial requirements, let the deficiency be made good by a tax-financed subsidy. On the other hand, if the total revenues should prove excessive, as they may well do if current unit costs of additional plant are far in excess of the unit costs of the existing plant, let at least a large part of the excess be recaptured by the community or by the nation through special taxation or else through outright public ownership.

What these economists here propose is a narrowing of the role of public utility rates as instruments of economic control. Relieved of any obligation to supply whatever funds may be required in order to maintain the credit of the enterprise as a going concern, rates can now be designed as single-purpose, precision instruments by which to control the demands of consumers for services of different kinds and in different amounts.[1] Even here, to be sure, rates will play an ancillary role in helping to finance the enterprise. But they need no longer be tailored with this subsidiary function in mind, since their deficiencies in this respect can be made good by another powerful instrument of economic control—that of taxation.

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We may restate this proposed limitation of the role of public utility rates by saying that these rates should be called upon to perform only those functions which they will perform when designed as if their sole purpose were to control the effective demand for the services. But an even more restricted role is contemplated by those more thoroughgoing marginalists whose view will be set forth in the next section. For, in their concern to use utility rates as devices by which to secure the optimum utilization of an *existing* utility plant, however excessive or deficient may be its present capacity in relation to the potential demand for its services, they would apply a *short-run* measure of marginal costs—a measure which may seriously detract from the usefulness of rates in the determination of the demand for and supply of utility services over extended periods of time.

History of MC Pricing

Before turning to the basic philosophy of marginal-cost pricing, we may comment briefly on its recent history.[2] The underlying idea is by no means new and is derived from the well-known principles of competitive-price determination developed in England by Alfred Marshall and other "neoclassical" economists of the late nineteenth century.[3] Under perfect competition as defined by these economists, the prices of all products "tend" to come into equality with their average unit costs of production, in that such an equality is one of the conditions of static equilibrium. But these prices also "tend" to equal marginal costs, both of short-run and of long-run varieties. There is no inconsistency among these multiple conditions of equilibrium as long as the products in question are produced at unit costs that either stay constant despite a change in the rates of output, or else increase with increases in output.[4] But if any product should be produced under a condition of *decreasing* unit costs, the maintenance of perfect competition is impossible.

[1] A French authority on marginal-cost pricing writes: "Vu sous ce jour, le prix n'a pas pour objet de rémunérer les dépenses du producteur au nom d'un quelconque principe d'équité, mais de motiver les décisions à venir des consommateurs de telle manière que celles-ci ne causent pas dans l'économie de dépenses irrationelles." M. Boiteux, "La Tarification des demandes en pointe: Application de la théorie de la vente au coût marginal," 58 *Revue générale d'électricité* 321–339 at 323 (1949).

[2] This history down to 1950 is well presented by Nancy Ruggles, "The Welfare Basis of the Marginal Cost Pricing Principle," 17 *Review of Economic Studies* 29–46 (1949–1950); "Recent Developments in the Theory of Marginal Cost Pricing," *ibid* 107–126.

[3] But Hotelling, in an article cited in footnote 6 below, gives to a French engineer, Jules Dupuis, the primary credit for developing the principle in its application to public works: "De la mesure de l'utilité des travaux publics," *Annales des ponts et chausées*, 2nd Series, Vol. 8, 1884. An English translation appears in No. 2 *International Economic Papers* 83–110 (1952).

Public utilities belong to a group of industries which are supposed to operate under the latter condition, at least in the typical case—a fact often cited as accounting for the need for their regulation as a substitute for competition. But the very condition which rules out actual competition also rules out any attempt to secure by regulation *all* of the good attributes of competitive prices including those of an equilibrium position in which prices are simultaneously equal to a whole variety of costs including average total costs, short-run marginal costs, and long-run marginal costs.

As already indicated, public opinion, insofar as it has been made aware of the very existence of the dilemma between a full-cost principle of competitive pricing and a marginal-cost principle, has tended to accept the former principle and to reject the latter. Indeed, until well into the twentieth century, the wisdom of this choice was not seriously challenged, head on, by the professional economists, most of whom accepted for public utility services, as for commodities in general, the traditional precept,

[4] One might suppose that, if a firm is producing under conditions of increasing unit cost, marginal costs will *exceed* average costs. And so they may if the average costs are an average of total costs defined and measured as a regulating commission would do for purposes of determining corporate revenue requirements under a fair-return standard of rate making. But under the theory of a competitive price, the total costs of production are defined as the costs to an enterpriser who must buy or rent all of his factors of production, including land sites, water rights, rights to use the public streets, etc., in a current, competitive market. In consequence, any excess earnings which might otherwise go to the enterpriser because of an ability to sell his product at a marginal cost in excess of average cost are obligingly gobbled up by landlords and by other recipients of rents or quasi rents.

"Let the beneficiaries bear the burden." Objections to this standard of financial self-sufficiency, while not completely ignored, were met with proposals for "practical" solutions, such as that for a type of rate base which hopefully would bring the average total costs of public utility services within a tolerable range of long-run marginal costs; [5] or such as that for the adroit use of rate discrimination designed to bring down toward marginal costs the charges for those classes and quantities of service for which the demand is *unusually* responsive to changes in price.

In 1937, however, this cautious—some writers would even say timid—attitude of the academic economists was sharply challenged by Professor Harold Hotelling, then at Columbia University, in one of the most brilliantly written articles in the history of utility rate theory.[6] In a sense, the economic philosophy of this article was orthodox in that it accepted a competitive-price rather than a "social-value" standard of rate making. But in another sense it was heretical, in that it regarded the marginal-cost attribute of a competitive price as more important for the purpose at hand than the average-cost attribute. This unconventional preference was based largely on the belief that the price system is almost uniquely qualified to perform the function of resource allocation or consumer rationing with maximum efficiency, whereas, in a regulated monopoly operating under conditions of decreasing cost with increasing output, it is not well qualified to perform the other functions of a competitive price (those other functions set forth in Chapter III, on the role of public utility rates) except in an auxiliary manner.

Both in this country and in Europe, Hotelling's thesis soon attained fame among the academic economists and led to a substantial flow of monographs and articles, some supporting his position and some defending the traditional principles of "full-cost" pricing.[7] The number of his *unqualified* supporters has been

[5] See p. 230, n. 7, *supra*, referring to an early debate between Professor Harry Gunnison Brown and myself on the relative merits of an original-cost or a reproduction-cost rate base.

[6] "The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates," 6 *Econometrica* 242–269 (1938). See also his later note, replying to Professor Ragnar Frisch, on "The Relation of Prices to Marginal Costs in an Optimum System," 7 *ibid.* 151–160 (1939). Hotelling had presented his main thesis at a meeting of the Econometric Society in December, 1933, though I believe not with his newer mathematical proof of its validity.

[7] See the articles and books noted by Nancy Ruggles in her previously cited re-

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very small. But this fact by no means belies the significance of his contribution to the theory of public utility rates. For he has substantially influenced the development of this theory, even on the part of those writers who still insist that "rates as a whole should cover costs as a whole."

It is a most disturbing commentary on the lack of communication in America between writers on the economic theory of public utility rates and persons engaged in the actual practice of rate making or rate regulation that few of these latter persons are familiar with, or interested in, the philosophy of marginal-cost pricing. Partly in the hope of bringing this philosophy to the attention of the practitioners, I close this book with the following elementary exposition and appraisal.

SHORT-RUN MARGINAL-COST RATE MAKING

For reasons already stated in Chapter XVII, the significance of the distinction between marginal-cost and average-cost pricing is far greater when the former alternative is taken to mean pricing based on *short-run* marginal cost than when it is taken to mean pricing based on a persistent or chronic or *long-run* marginal cost. While the broad distinction is significant even under the latter interpretation, it is revolutionary only under the former. We shall therefore first consider the case for marginal-cost pricing in its former, uncompromising sense—the sense accepted by Hotelling. A technical treatment of its rationale would be an elaborate procedure, involving mathematical analysis based on a host of simplifying assumptions. But a general idea of the argument in its favor is easily presented—all the more so here since it is implicit in the more familiar acceptance of "out-of-pocket cost," the popular version of marginal cost, as a measure of *minimum* rates.

By way of illustration, let us borrow Hotelling's example of a very simple type of public utility plant, that of a toll bridge for motor vehicles. The bridge, let us say, is owned and operated by a public authority, which has financed its construction by the sale

view (footnote 2) of the literature. Compare, e.g., the defense of full-cost pricing by Professor R. H. Coase with the qualified support of marginalism by Professor William S. Vickrey: Coase, "The Marginal Cost Controversy," 13 N.S. *Economica* 169 (1946); Vickrey, "Some Objections to Marginal-Cost Pricing," 56 *Journal of Political Economy* 218 (1948). For a significant book on the subject by a socialist economist, see Burnham P. Beckwith, *Marginal-Cost, Price-Output Control* (New York, 1955).

of revenue bonds. In line with the traditional principle that public utility rates must cover total costs, the toll must be set at the minimum deemed necessary to pay the annual maintenance costs of the bridge plus fixed charges, which are here composed of interest charges plus amortization. Ignoring for simplicity the limited possibilities of differential tolls, let us assume that the required toll is $1 per crossing. This toll reflects the average total cost of the service.

Now let us note the economic harm done by this orthodox attempt to base utility rates on the financial principle that "every tub should stand on its own bottom." Assume, first, that the bridge has a capacity at least sufficient to accommodate all traffic forthcoming on a toll-free basis. On this assumption, the levy of the $1 toll is economically unsound, since its deterrent effect will prevent the bridge from being put to its fullest feasible use. Indeed, on the only slightly inaccurate assumption that even the maintenance costs of the bridge will not be affected by the amount of use, the imposition of any toll whatever is unsound.[8] All of the costs being "sunk costs," they should have been paid for, directly or indirectly, entirely by taxation, just as are city streets and sidewalks.

But what about the situation that will probably arise, sooner or later, when the bridge traffic, especially if stimulated by freedom from tolls, threatens to become too congested for safe handling by the present bridge? When this time arrives, a toll should be imposed. But the amount of the toll should be in no way determined or limited by the authority's financial needs. Instead, it should be made high enough to preclude serious traffic congestion by limiting the use of the bridge to those persons who are ready to pay the potential "market-clearing" price for this use. In an extreme situation in which an unexpected or unprovided-for growth in potential demand for river crossings makes the present capacity of the bridge grossly inadequate, a toll as high as, say, $10 might well be required. This toll should be removed completely if and when a later enlargement or duplication of the bridge again makes the capacity redundant.

But would not the imposition of this market-clearing toll violate the very principle of marginal-cost pricing which Hotelling has advanced as a general substitute for pricing based on average total cost? The answer is no, although the definition of "marginal cost" must here be extended so as to give it a relevant meaning without sacrifice of its economic significance. For, if the bridge traffic has now reached its uppermost limit, the marginal social cost of permitting any one vehicle to use the bridge is measured by the value of the opportunity of use that must be denied to the highest excluded bidder. This bidder is the potential user who is barely deterred by the obstacle of the $10 toll. In other words, the relevant marginal cost, instead of being a production cost, is here an exclusion cost as measured by the marginal value of the service.

value of service pricing ?

Later writers have elaborated on Hotelling's bridge illustration by noting the "economic distortion" that may result from the imposition of different tolls on different bridges or highways designed to meet separate tests of financial self-sufficiency, project by project.[9] Where optional routes are available for trucks and passenger cars, the resulting mixture of high-toll, low-toll, and no-toll routes is almost sure to lead to serious economic wastes, because it motivates the road users to base their choices on relative money costs that do not reflect relative social costs.

But the toll-bridge illustration is merely a simple example of the asserted advantages of marginal-cost pricing over full-cost pricing applicable to all public utilities—applicable, in short, to a

[8] This statement requires qualification since it makes the simplifying assumption that, up to some definite point of "serious traffic congestion," the quality of the bridge-crossing service remains unaffected by the traffic. In fact, however, this quality, as measured by speed, comfort, and safety, will deteriorate gradually with increases in traffic, since each additional driver will get in the way of other drivers. As long as the bridge remains toll free, every user therefore imposes a cost upon other users which he is not required to defray. This means that the marginal *social* cost of bridge service then exceeds the cost imposed upon any one user. In theory, there should be a toll sufficient to deter use of the bridge by anyone to whom the value of the service is not sufficient to warrant the extra traffic congestion which he imposes on other users. See a much cited discussion of this point by Professor Frank W. Knight, taking issue with a position previously held by Professor Pigou: "Some Fallacies in the Interpretation of Social Cost," 38 *Quarterly Journal of Economics* 582–606 (1924), reprinted in Knight, *The Ethics of Competition* (New York, 1936). The subject is very important in the field of highway-transportation economics and, as will be noted later, has an important bearing on rate-making policies for local transit. See Martin Beckmann, C. B. McGuire, and Christopher B. Winsten, *Studies in the Economics of Transportation*, a series of studies for the Cowles Commission (New Haven, Conn., 1956). Telephony presents a situation reverse from that here mentioned in that the addition of another telephone subscriber may *add* to the "value" of the service enjoyed by the other users.

[9] Particularly William S. Vickrey, "Some Implications of Marginal Cost Pricing for Public Utilities," 45 *American Economic Review, Proceedings* 605–620 (1955). Professor Vickrey has become the leading American authority on marginal-cost pricing in its application to public utilities.

vitally important group of noncompetitive industries with respect to which the gap between the two types of pricing is especially wide and especially menacing. To be sure, marginal costs even of a short-run variety are less likely to be merely trivial for these other utilities than for toll bridges. Moreover, opportunities for rate discrimination as a means of full-cost recovery are likely to be much better. But the general principle still applies. And, as to the use of discrimination as a device by which to jump the gap between average-cost and marginal-cost standards, Hotelling cites some unhappy consequences of the attempts by railroads to make these jumps as failing to justify any complacency toward this device for the attainment of essentially inconsistent advantages.

In recent years, many railroad properties, including rights of way, tracks, and passenger terminals, have become redundant as a result of the growth of competing forms of transportation, combined with technological progress in signalling, etc., with respect to main line hauls. This redundancy, moreover, may last for a long time—some of it as long as the structures remain standing. Meanwhile, attempts to put the existing properties to their best available use are seriously handicapped by the largely hopeless attempts of the railroads to secure a "fair return" thereon and by the pressure upon the Interstate Commerce Commission to sanction rates designed to yield such a return.[10] Professor Hotelling's proposal would meet this situation by a general reduction of railroad rates to short-run marginal costs. This reduction would apply to entire railroad rate levels instead of being confined to a discriminatory and distortionate reduction of those particular rates that must be reduced in order to meet the immediate and direct competition of the road and water carriers. Any resulting fair claims by railroad investors for restitution for this retroactive change in rate-making policy would be cared for, presumably, by a government-financed indemnity.

[10] The seriousness of the handicap can be appreciated when one recognizes that, if a railroad or utility company were entitled to annual changes in rate levels designed to yield a stable "fair rate of return" on the net investment in, or so-called value of, its property, year after year, it would need to raise rates during years of depression and lower them during years of prosperity—a viciously cyclical procedure. Indeed, the Interstate Commerce Commission actually gave the railroads permission to make emergency rate-level increases in the depression period of the 1930s. Marvin L. Fair and Ernest W. Williams, Jr., *Economics of Transportation*, rev. ed. (New York, 1959), p. 576.

CRITIQUE OF PROPOSAL TO FIX RATES AT SHORT-RUN MARGINAL COSTS

Reserving for a later section a discussion of the much milder proposal to base rates on marginal costs of a long-run character, let us now consider critically the merits of the far more drastic proposal to base rates on short-run marginal costs.[11] Already some of the more serious objections have been noted in Chapter XVII, which discusses the relative merits of the two major types of marginal costs as measures of *minimum* rates.

First, let us recall that, with most public utilities, the really significant choice is not a simple choice between *marginal* cost and *average* cost as the basis of rate making. To be sure, the assumption that the rate maker faces this dire dilemma is not too far from reality in the toll-bridge example, since here the practical opportunities for rate differentiation are severely limited. Hence the bridge example presents an unusually forcible case for the adoption of marginal-cost pricing or, at least, for the abandonment of any attempt to make each particular bridge rest on its own financial foundations. But with railroads and most other utilities, there exists a wide variety of plausible rate structures, including those which resort to multi-part rate making, block rate making, and various forms of discriminatory pricing. Most of the rate structures now in effect are subject to material improvement with advances in the technique of rate design but without abandoning the total-cost principle. While none of them can be expected to have *all* of the consumer-rationing advantages of unqualified marginal-cost pricing, neither can they be assumed to result in economic losses of the order of magnitude of those suggested by an attempt to make a particular toll bridge financially self-sufficient through a uniform charge of so many cents or dollars per vehicle per crossing. Unfortunately, however, the measures of the relative gains and losses of marginal-cost pricing versus any given type of discriminatory, full-

[11] For one of the most well-balanced critical appraisals of marginal-cost pricing, both of the short-run and the long-run varieties, see Robert W. Harbeson, "A Critique of Marginal Cost Pricing," 31 *Land Economics* 54–74 (1955). Harbeson comments on one criticism not discussed in this brief chapter: that the supporters of marginal-cost pricing for regulated monopolies ignore the supposed failure of unregulated prices to come into accord with marginal costs under the most widely prevailing types of competition, namely, "imperfect" or "monopolistic" competition.

cost pricing that are suggested by economic theory are impossible to apply in terms of present factual knowledge.

Secondly, we must consider whether or not the almost undeniably superior efficiency of short-run marginal-cost pricing as a means of securing the optimum utilization of a plant of temporarily redundant capacity [12] warrants the surrender or impairment of all of the other important functions of utility rates, even the function of aiding in the control of the demand for and supply of utility services in the longer run. By and large, the major influence exercised on consumer demand for utility services by any current rates of charge for these services is an influence based on the expectation that these rates indicate, at least in a general way, the rates that will remain in effect over a considerable period of time. For it is the anticipated, fairly long-run costs of service which a potential consumer wisely takes into account when he faces a decision whether to commute from New Jersey to New York despite the daily payment of tolls on the George Washington Bridge; or whether to equip his home with an electric range or with electric space heating; or whether to locate his aluminum plant on the St. Lawrence River rather than in the state of Washington. Once having become dependent on the services required for the operation of expensive complementary equipment, the consumer's responsiveness to temporary changes in rates of charge will probably be very limited. In short, the price elasticity of demand for utility services can be expected to be much greater in the fairly long run than in any very short period of time. But if utility rates were to be made as volatile as would be required by the mandate of conformity to short-run marginal costs, they would deprive consumers of those expectations of "reasonable continuity" of rates and of rate relationships on

Stability

[12] Even this claim of superiority must be conceded only on the assumption that the better-than-nothing use of temporarily excess capacity will not materially interfere with possible emergency use. Instant readiness to serve may well be the best use of idle capacity. Professor Eli W. Clemens had this point in mind in doubting the wisdom of proposed attempts by electric utilities to encourage three-shift factory loads by the concession of very low rates for off-peak industrial service. 23 *Southern Economic Journal* 92–93 (1956). Resort to three shifts, he recalled, was one of the major ways by which the country avoided a menacing power shortage during the Second World War. "One day's loss of lives," he added, "constitutes quite a lot of marginal disutility." To the same effect, see Emery Troxel, "Reserve Plant Capacity of Public Utilities," 26 *Land Economics* 145–161 (1950), quoting at p. 150 from a significant book by the South African economist, Professor W. H. Hutt, entitled *The Theory of Idle Resources* (London, 1939).

which they must rely in order to make rational advance preparations for the use of service.

Thirdly, and closely related to the objection just mentioned, there is the probability that short-run marginal-cost rate making would deprive utility managements of an almost essential guide to intelligent decisions as to the needs for plant expansion. Under prevailing systems of rate making, managements base their estimates of future service requirements on a projection of past growth trends in the consumption of different classes of service. Their provisional assumptions that these same trends will persist in the future are premised on the expectation, not necessarily that rates will stay fixed, but at least that they will remain in fairly stable relationship to the prices of other products. But if current rates were to rise and fall with changes in current marginal costs, the resulting unpredictability of future demands might seriously handicap managements in timing their programs of construction.[13]

In his defense of short-run marginal-cost pricing, Professor Hotelling argued that the construction and expansion of public utility plants and of other public works are seriously retarded by the traditional and fallacious assumption that the economic justification of a proposed project depends on a finding that it can be made to yield revenues at least sufficient to cover its total operating and capital costs. This assumption, he declared, ignores the failure of the anticipated revenues to reflect those benefits that will accrue to consumers in the form of "consumers' surplus"—benefits measured by the excess in the highest prices that consumers would be willing to pay for different amounts of service rather than go without, over the prices that they will be required to pay under any feasible system of more or less uniform prices. While this point certainly suggests a complicating factor in a cost-benefit analysis of a large public-works project, it is not a convincing argument for the gen-

[13] But my colleague Professor Vickrey, who has kindly read this chapter in manuscript, disagrees sharply. "Far from making the timing of construction more difficult," he writes, "fluctuating rates would provide an instrument whereby demand could be adjusted to supply, so that the consequences of an unexpectedly large surge in demand, or failure of supply due, say, to drought, would be much less disastrous. Therefore a much smaller margin of excess demand to protect against these contingencies would be necessary. At the other end of the scale, excess capacity provided by overoptimistic planning would be utilized more fully so that mistakes in this direction would be less wasteful also. Compare Ontario Hydro in the depression." I have cited the Ontario Hydro experience in an earlier chapter, p. 335, *supra*.

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eral abandonment of a financial self-sufficiency test of utility plant expansion. For, if consumers' surplus is to be included in a calculation of the benefits derivable from any proposed expansion, then it must also be included on the cost side of the cost-benefit balance sheet, in the estimate of the "opportunity costs" of public utility plant construction—costs which may include the withholding of economic resources from the construction of plants designed to produce other products, the sale of which would also yield a consumers' surplus.[14]

In the fourth place, we must consider the question whether the claimed advantages of short-run marginal-cost pricing as a means of improving utility rate structures, even if substantial, would still be great enough to warrant the required resort to tax-financed subsidies. The most popular objection to subsidies is based on the declared unfairness of a system of rates which requires nonconsuming taxpayers to subsidize the beneficiaries. But quite aside from any such considerations of income-distributive justice, there are serious political objections to wholesale extensions of public subsidies: namely, that legislative grants of subsidies come so largely through the efforts of pressure groups and of regional interests which are under little impulse to weigh the benefits to themselves against the costs to other people. Even so, of course, many subsidized public projects will be justified, since many of them will have great social value even though their benefits are not of the type that can be made vendible except, perhaps, to a limited degree. But a general proposal to bring the country's railroad and other public utility systems into this category for the sake of the possible benefits of short-run marginal-cost pricing seems to me too portentous politically to deserve favorable consideration.

Finally, and apart from any general objections to a scheme of rate making which taxes nonbeneficiaries for the benefit of the beneficiaries, there is another reason for a refusal to impose upon

[14] The traditional cost-benefit analyses of public-works projects by the U.S. Corps of Army Engineers and the other government agencies include no allowances for consumers' and producers' surpluses as such, although they take account of the same phenomena in their estimates of indirect benefits. A pioneering study of public-project evaluation by Otto Eckstein seems to support the conclusion that, on the whole, the traditional analyses follow techniques tending to result in overoptimistic conclusions as to the ratios of benefits to costs. *Water-Resource Development* (Cambridge, Mass., 1958). See also John V. Krutilla and Otto Eckstein, *Multiple Purpose River Development* (Baltimore, 1958).

the country's existing tax system a part of the burden now borne with only moderate efficiency by its price system. This reason is that the only forms of taxation still available to carry the extra load are of a highly imperfect nature, with the result that the additional taxes might have more serious repressive or distorting effects on the nation's economy than full-cost-recovery rate making has on the outputs and prices of utility services. In his article in 1938, Hotelling recognized this danger and proposed to meet it by the use of certain taxes arguably not subject to shifting, such as taxes on land-site values, inheritance taxes, and income taxes. But in view of the critical subsequent rise in the nation's tax burdens, any hope of finding additional sources of public subsidies in the form of yet unused taxes that are "neutral" in their effect on the allocation of the country's economic resources seems extremely remote. Certainly neither the corporate nor the individual income tax could any longer be regarded as such a source. The most promising alternative might well be the resort to a widely spread excise tax, such as a sales tax, the use of which would permit the reduction of the wide gaps between the rates and the marginal costs of utility services in exchange for a slight increase in the narrower gaps between the prices and the marginal-production costs of commodities and services throughout a much larger sector of the economy.[15]

THE ALTERNATIVE STANDARD OF LONG-RUN MARGINAL COSTS

One may summarize the foregoing criticisms of the proposal to base utility rates on short-run marginal costs by saying that, in giving sole consideration to one very limited though important function of prices, that of securing the optimum utilization of whatever plant capacity exists at a particular time, it would sur-

[15] The sales tax or some similar, widely applied, excise tax, once so largely opposed by economists in view of its regressive character, has regained status among many economists, who recognize the serious distortion effects of the current high income taxes and of other taxes of a designedly progressive nature. But in view of the nation's need to devote far more of its resources to nonvendible products of high social value, such as in public education, health service, and recreation—a need so persuasively argued by Professor John Kenneth Galbraith in his *The Affluent Society* (Boston, 1958), one may doubt the wisdom of resort to excise taxes in order to subsidize the production of vendible public utility services. Indeed, the mere cost of administering such taxes might offset whatever value they might otherwise have in securing a better allocation of resources.

render other functions of even greater importance including, particularly, that of the long-run control of the demand for and supply of utility services. Mainly for this reason, I take it, the proposal has won little support even from those economists who are most impressed with the shortcomings of full-cost standards of rate making.

But another version of the marginal-cost principle has enlisted more sympathetic interest among academic economists: the principle of rate making based on long-run marginal costs. As yet, at least, even this far milder version has made no appeal to the legislatures or rate-making practitioners of this country or of England. But on the European continent it has made some headway among the administrators of the nationalized railroads and utilities.[16] And in France the principle has already been put into partial application, particularly by the electric power system (Électricité de France).[17]

The basic distinction between short-run and long-run marginal cost has been discussed at length in Chapter XVII and need not be restated here. Advocates of either type of cost as a measure of reasonable rates accept, as the primary objective of rate-making policy, an optimum-allocation or consumer-rationing objective even if its realization calls for the surrender of the traditional principle of financial self-sufficiency. But the long-run marginalists emphasize the need for a relatively stable and continuous level or trend of rates, in the belief that the rates which have the most important effects on the demand for and provisions for utility services are rates that may be expected to persist over a considerable period of

[16] See *The Theory of Marginal Cost and Electricity Rates*, published by the Organization for European Economic Co-operation (Paris, 1958).

[17] See Thomas Marschak, "Capital Budgeting and Pricing in the French Nationalized Industries," 33 *Journal of Business of the University of Chicago* 133–156 (1960). The engineer-economists of these industries—notably Mr. Marcel Boiteux, Vice President in charge of economic studies, Électricité de France—have been in advance of any other writers in their contributions to the principles of rate making based on marginal cost. In addition to the articles cited in footnotes 10 and 21 of Chapter XVIII, footnote 25 of Chapter XIX, and footnote 1 of the present chapter, see Boiteux, "La Vente au coût marginal," *Revue française de l'énergie*, Dec., 1956; "Le Tarif vert d'Électricité de France," *ibid.*, Jan., 1957; "Les Tarifs de la concession d'alimentation générale d'E.D.F.," in a later issue of the *Revue* for 1957. See also Gabriel Dessus, "The General Principles of Rate-Making in Public Utilities," translated, *International Economic Papers*, No. 1, 5–22 (1951); Dessus and Fleurquin, "Les Tarifs de gaz et d'électricité et l'orientation du consommateur," 58 *Revue d'économie politique* 513–546 (1948).

time. Hence, the most important marginal costs for purposes of rate control are the normal or persistent marginal costs rather than the very short-lived marginal costs that may fall almost to zero in some brief period of time, only to rise to several times average total costs soon thereafter. For this purpose, however, "long-run" marginal costs must be given a flexible and frankly indefinite interpretation, since any attempt to fix rates today by reference to cost functions that may not materialize, say, for twenty-five years or more would be utterly foolish. In short, the costs that should be covered by the rates are the marginal costs that are "permanent" in the sense used by a dentist when he refers, optimistically, to a permanent rather than a temporary filling.

Although long-run marginal-cost rate making must rest its claim for acceptance primarily on its asserted superiority from the standpoint of optimum resource allocation, it has an important secondary advantage over the short-run alternative in requiring far less drastic departures from the orthodox requirement of full-cost pricing. As noted in Chapter XVII, this conclusion follows from the very definition of long-run marginal cost—a definition which treats all costs as varying with rates of output, even the so-called fixed costs. Indeed, with utility enterprises that have already attained the major economies of large scale, rates set at long-run marginal costs may be sufficient, or more than sufficient, to yield total revenue requirements. Under these conditions, the proposal to adopt marginal-cost pricing of the type now under review would not conflict with the maintenance of the traditional principle that rates in the aggregate must cover total costs. But down to the present time, both the theory and the practice of utility cost analysis are too primitive and too meager to supply an answer to the question how prevalent such conditions may be.[18]

The very reasons, however, which make the proposal to set utility rates at long-run marginal costs more "practical" than the proposal to adjust rates to short-run changes in marginal costs also constitute reasons for doubting its net advantages over full-cost

[18] In an unpublished study based on Interstate Commerce Commission data for 1936, the results of which he presented at the meeting of the Econometric Society in Montreal, Sept., 1954, Professor William S. Vickrey has estimated that, for American railroads as a whole, long-run marginal costs of freight service may well constitute from 75 to 80 per cent of average total costs. He notes that, as his study was based on cross-section comparisons at different actual densities of traffic, "it represents the extreme long-run end of the spectrum of marginal costs."

pricing as a generally applicable basis of rate control. Its best claim for serious consideration can be made in those situations in which the traditional attempt to make "rates as a whole cover costs as a whole" must be judged hopeless or intolerably wasteful in the light of experience. A verdict of this nature would almost surely apply to the city rapid-transit systems and may well apply to the entire American railroad industry, taken as a whole. The intercity railroads are vainly struggling to earn capital-attracting rates of return against the competition of heavily subsidized alternative forms of transport. Their chances of survival might be better if all of their rates, and not merely the rates for commodities or routes that face direct competition, could be brought down to levels set by standards of marginal costs over an extended period of time.

But one must not assume that marginal-cost rate making, whether short-run or long-run, offers a general solution of all of those rate-making problems raised by the inability of a utility to cover its full costs by the sale of its services. For there are many possible explanations of this inability other than the presence of a gap between marginal costs and average total costs. The local transit systems, for example, face competition from drivers of private cars, each of whom gets in the way of the others by adding to the traffic congestion. Under these conditions, subway fares should probably be set at less than marginal costs if the lower fare will serve to diminish congestion on the surface. A somewhat similar situation prevails on the railroads, which must compete with road and water users whose marginal private costs of using public highways and waterways understate the marginal social costs of maintenance and expansion. For these reasons, as well as for the reason that national-defense considerations may require the maintenance of railway facilities that are excessive for peacetime use, the marginal-cost-pricing philosophy of rate making is subject to important deviations in the direction of "social" principles of rate making.

MARGINAL-COST PRICING AND PUBLIC UTILITY TAXATION

Even though marginal-cost pricing may never win, or deserve to win, such widespread and unqualified acceptance as to supersede

the traditional principle of full-cost coverage for entire rate levels, it may nevertheless have increasing influence of an indirect nature as it gains in familiarity, in theoretical development, and hopefully in the prestige of successful partial application in France and elsewhere in Europe. One possibility—remote, I fear, for the immediate future—is that it may influence utility and railroad taxation in a downward direction. This possibility calls for a comment. But the comment will be brief, since the subject of taxation is far beyond the scope of the present book.

In a study made in the early 1920s,[19] Dr. Herbert D. Simpson of Northwestern University concluded that the history of American railroad and utility taxation could be divided into four stages. The first stage, which was in the development period of the canals, turnpikes, and railroads, was one of "reverse taxation"—of outright governmental subsidy. The second stage was that of complete or partial tax exemption. In this period, which ended around the middle of the nineteenth century, proposals to tax the railroads were regarded as "radical." The third stage was that of attempted uniformity of taxation—a uniformity that proved impossible to achieve because of the difficult problems of utility property-tax assessment. The fourth and final stage was that of special types of utility taxation, many of which discriminated harshly against the utility companies as compared to other taxpayers. Thus, said Dr. Simpson, "the pendulum in this field of taxation has swung from outright subsidy and exemption at one extreme, through the uniformity period, and over to high and discriminatory taxes at the other extreme."

When Dr. Simpson wrote, he believed that the time was ripe for a return to a policy of uniformity, although this uniformity might best be approached by modification of the special utility taxes rather than by the inclusion of utility properties under general-property taxation. And his view may well have reflected the general

[19] Manuscript of lecture on "Taxation of Public Service Companies" published in Herbert B. Dorau, ed., *Materials for the Study of Public Utility Economics* (New York, 1930), pp. 471–490. Professor Harold M. Groves divides utility-tax history into three periods: those of (a) subsidy, ending at the end of the nineteenth century, (b) neutrality, ending with the depression of the 1930s, and (c) "special burdens" from 1930 to date. *Financing Government*, 5th ed. (New York, 1958), p. 336. One tax expert whose name escapes me writes that public utility companies "are taxed, for the most part, as though the regulating commissions do not exist; tax authorities and regulators scarcely seem aware of their conflicting purposes."

trend of American tax philosophy at that time. But there soon took place a tendency to revert to discriminatory taxation. This tendency may have been stimulated by a growing belief that utility rate regulation, handicapped by the Supreme Court's current rulings on a "fair-value" rate base and by the growth of uncontrollable holding companies, was proving impotent to prevent utility companies from earning excessive profits. Taxation was therefore looked upon as a device by which to offset the shortcomings of regulation.

Since the Second World War, this excuse for high utility taxation has lost most of its force. But its place has been taken by the legislative recognition of the utility companies as unusually convenient and stable sources of revenue for hard-pressed government treasuries. Hence, utility services have been subject to special taxes, including excise taxes some of which are charged directly to the consumer, the others being charged to them indirectly through their inclusion as legitimate operating deductions whenever rates are readjusted by public service commissions.

At the present time, the sum total of local, state, and Federal taxes paid by the utility companies amounts to a substantial fraction of their gross revenues. For the private electric companies in the aggregate, this fraction was reported as 21 per cent in 1957 but came to 25 per cent or more for specific companies. For telephone companies the ratio of taxes to operating revenues has been even higher, on the order of 30 per cent. Typically, somewhat more than half of a utility's tax bill is for Federal corporate income taxes. But, under a rule laid down by the Supreme Court in the 1920s,[20] allowance for these taxes is also included in a commission's calculation of a company's total revenue requirements.

Assuming, as it seems plausible to assume, that this complex of utility taxes imposes a proportionately higher tax burden on the prices of utility services than nonutility taxes impose on nonutility commodities and services, there tends to result a misallocation of economic resources—an allocation of inadequate resources to the production of electricity, railroad transportation, etc. And, to the extent to which utility services are produced under conditions of declining unit costs, this discrimination compounds the shortcomings of a rule of rate making which requires a utility company to recover its total costs by charges for its various services. Indeed, the most practical way to avoid or minimize these shortcomings may well be through tax discrimination in the opposite direction.

[20] Galveston Electric Co. v. Galveston, 258 U.S. 388, 399 (1922).

But important as is the likelihood that, on the whole, utility taxes are higher than they should be, relative to the taxes embodied indirectly in the prices of nonutility commodities and services, even more important is the high probability that these taxes discriminate against the supply of *particular types* of utility services. The most outstanding example of this situation is that in the field of transportation, where the heavily taxed railroads must compete with other, subsidized forms of transportation. As long as this situation of subsidy exists for road, water, and air carriers, sound economic policy dictates a closer approach to symmetry by the grant of complete or partial tax exemption to the railroads.

I close this book by raising one other serious question about utility taxation in its relation to rate-making policy. It concerns the marked differences between the high taxes imposed upon the private electric utilities of this country and the relative freedom from taxes or tax equivalents enjoyed by the electric plants operating under Federal, state, or local ownership. Needless to say, opponents of public ownership bitterly resent this tax differential. But even those who, like the present writer, favor a substantial but limited number of publicly owned electric systems, such as that of the Tennessee Valley Authority, cannot fail to be concerned with a tax situation that makes so difficult any fair comparison between private-plant and public-plant performance.

By all means the most desirable way by which to secure greater comparability of performance would be substantially to reduce, if not to eliminate, private utility taxation. But if the only politically feasible way to secure equalization is to raise the tax burden imposed on the services of the public plants, there then arises a dilemma, and the choice of the less seriously penetrating horn is not easily made.

In earlier years, when the country's great Federal hydroelectric projects were in their development stages, tax exemption of these projects seems to me clearly to have been the wiser choice. Today, when these public projects are now full-fledged going concerns, the issue is far less clear. There still remains one strong argument in favor of continued tax exemption: namely, that the country as a whole may benefit from the presence of a limited number of tax-free plants which can serve as experiment stations in developing and supplying the demand for power by means of promotional rates lower than those with which a tax-burdened enterprise can afford to experiment. The Tennessee Valley Authority's experience in the widespread promotion of a house-heating load may be of this nature. But when public plants receive a high tax advantage, whether for this purpose or any other, they lose much of their value as yardstick plants against which to measure private-plant performance. Moreover, freedom of public plants from the Federal taxation imposed on private utilities gives to public ownership a factitious advantage over private ownership, viewed from the self-interested standpoint of a local community, that must interfere with an unbiased appraisal of the relative merits of the two forms of organization from the standpoint of the nation. My present, tentative, opinion is that the weight of the argument favors attempts to put publicly and privately owned electric power systems more nearly on a par, tax-wise, by a combination of a heavier public tax load and a lighter private tax load. But this is not a book on public utility taxation or on public ownership, and the questions raised here demand thoroughgoing separate studies.

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Smart Rate Design for a Smart Future, Appendix D

The Specter of Straight Fixed/Variable Rate Designs and the Exercise of Monopoly Power

By Jim Lazar

Introduction

A number of electric utilities have proposed what is called "straight fixed/variable" rate design (SFV), in which all costs claimed to be "fixed costs" are recovered in a fixed monthly charge, and only those costs that are considered "variable" are recovered on a per kilowatt-hour (kWh) basis. While most have focused only on distribution costs, a few have gone further, proposing that generation and transmission investment-related costs be included in monthly fixed charges.[1]

In accounting terms, the only truly "fixed" costs are interest and depreciation. All other costs, including the shareholder return, associated income taxes, labor, and revenue-sensitive costs are technically "variable" costs — they change from month to month and from year to year. Utilities often define "fixed costs" very loosely, including these other costs, as well as all distribution costs and sometimes even some generation-related costs in this category.

High fixed charges provide utilities with stable revenues, but have many adverse impacts on electric consumers and energy policy. We discuss some of these below.

Disincentives to Public Policy Goals

Energy Efficiency

Given a defined electric revenue requirement, a higher fixed charge results in a lower per kWh rate. Table D-1 shows an illustrative example, comparing a utility with a typical customer charge of $7.00/month and a $.10/kWh energy charge with one imposing a $57/month customer charge, but only a $.05/kWh energy charge. Both have the same bill — $107.00/month — for the average customer, but the higher customer charge results in a 44% larger bill for a typical apartment dweller or other small user, and a savings of 29% for a very large home.

Table D-1

Example of Fixed Charge Effect

Rate Design		Typical Rate	SFV Rate	Difference
Customer Charge		$7.00	$57.00	
Energy Charge		$0.10	$0.05	
Customer Bills	**kWh/month**			
Average Customer	1000	$107.00	$107.00	0%
Apartment Dweller	500	$57.00	$82.00	44%
Extra-Large Residence	2500	$257.00	$182.00	-29%

The impact of this on customer-driven energy efficiency can be quite dramatic. A high-efficiency air conditioner or window replacement that might have a 5-year payback period for the consumer at $.10/kWh would have a 10-year payback at $.05/kWh. Many consumers will be hesitant to invest in energy efficiency if the savings are smaller.

Competitive Impact on Renewable Energy Development

The same adverse effect can result for customer renewable energy development. A customer who might invest in a solar photovoltaic system when they can avoid $.10/kWh in the utility rate may be able to put together a combination of tax incentives and financing to make this an attractive investment. At $.05/kWh, it is much less likely. At the same time, a low-use (high efficiency plus on-site solar) custom-

1 For example, Madison Gas and Electric in 2014 proposed a $57/month fixed charge, and Hawaiian Electric Company proposed a $55/month fixed charge, plus an additional $16/month for customers with photovoltaic systems. The MG&E proposal was resolved with a $19/month customer charge, and the HECO proposal was significantly modified to a $25 monthly minimum bill, and a lower credit of only $0.18/kWh for excess solar energy exported to the grid from new PV installations.

er considering going off the utility grid would have a much stronger incentive to do so. The cost of their storage bank would only need to compete with the high fixed cost attributable to the average customer, but since they produce much of their power on-site, they would need a smaller than average storage capacity to store a portion of their power needs. The customer, of course, would then be obligated to supply all his/her power needs. Losing a customer permanently further exacerbates the lost revenue issue.

Low-Income Households

The vast majority of low-income households use below-average amounts of electricity, and will pay higher bills with an SFV rate design. Table D-2 shows an analysis prepared

Table D-2

Low-Income Household Usage

Average 2009 household electricity usage (kWh) by status above or below 150% of poverty

Energy Information Administration, Residential Energy Consumption Survey Reportable Domain	Average Usage (kWh) Sorted by Income Level: Above 150% Poverty Level	At or Below 150% Poverty Level	All Households	Percentage Difference Between Average KWH Low-Income and Non-Low-Income Households
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	8,453	5,920	7,940	**-30.0%**
Massachusetts	7,364	5,353	6,967	**-27.3%**
New York	7,039	5,431	6,578	**-22.8%**
New Jersey	9,155	6,760	8,902	**-26.2%**
Pennsylvania	10,733	8,992	10,402	**-16.2%**
Illinois	10,771	9,430	10,392	**-12.5%**
Indiana, Ohio	11,559	10,224	11,220	**-11.6%**
Michigan	9,206	7,508	8,695	**-18.4%**
Wisconsin	8,827	7,961	8,672	**-9.8%**
Iowa, Minnesota, North Dakota, South Dakota	11,288	8,198	10,719	**-27.4%**
Kansas, Nebraska	10,800	10,030	10,633	**-7.1%**
Missouri	13,775	13,602	13,740	**-1.3%**
Virginia	15,088	11.237	14,442	**-25.5%**
Delaware, District of Columbia, Maryland, West Virginia	14,437	12,711	14,100	**-12.0%**
Georgia	15,452	13,823	14,917	**-10.5%**
North Carolina, South Carolina	14,717	12,620	14,045	**-14.2%**
Florida	15,679	12,358	14,858	**-21.2%**
Alabama, Kentucky, Mississippi	16,307	12,915	15,236	**-20.8%**
Tennessee	15,766	13,512	15,132	**-14.3%**
Arkansas, Louisiana, Oklahoma	14,852	13,560	14,392	**-8.7%**
Texas	15,157	11,816	14,277	**-22.0%**
Colorado	7,745	5,752	7,439	**-25.7%**
Idaho, Montana, Utah, Wyoming	11,349	13,126	11,753	**15.7%**
Arizona	14,970	11,218	14,105	**-25.1%**
Nevada, New Mexico	10,580	9,643	10,369	**-8.9%**
California	7,256	5,732	6,888	**-21.0%**
Alaska, Hawaii, Oregon, Washington	12,841	11,726	12,570	**-8.7%**
Total	**11,734**	**10,692**	**11,320**	**-14.2%**

by the National Consumer Law Center that examines the usage of low-income households. It shows that households below 150% of the federal poverty level use between 9% and 30% less electricity than the average of all households.

However, there are some low-income households with high electricity usage, including large (sometimes multigenerational) households, but in most cases this is the result of low levels of energy efficiency that can be addressed with programmatic conservation. In general, low-income advocates, consumer advocates, and environmental advocates favor addressing the special needs of these families with specific programmatic approaches or direct financial assistance, rather than setting a base rate design that favors high-users.[2]

Apartment and Urban Dwellers

Multi-family housing residents also have below-average usage and are adversely impacted by high fixed charge rate designs. These residents typically have below-average dwelling size, below-average residents per household, and below-average usage. They are also quite obviously cheaper to provide electric distribution service to — since they are close together and many customers are served by a single distribution transformer. As we discuss in Chapter IV, this has many impacts on the cost of utility service and appropriate rate design.

SFV Can Cause a 15% Increase in Electric Consumption

When Madison Gas & Electric originally proposed a $69/month customer charge, it also proposed reducing the per kWh rate from $.14/kWh in winter and $.15/kWh in summer to about $.04/kWh. Using the economic principle of elasticity (higher prices result in a lower quantity demanded), and applying a moderate elasticity factor of -0.2 (a 1% increase in price results in a 0.2% reduction in usage), The Regulatory Assistance Project estimated that the proposed rate design could result in about a 14.5% increase in usage over time.[3] The expectation is that consumers would raise thermostats, defer efficiency investments, and be less attentive to simple things like turning off unused lights.

Other Potential Adverse Impacts

A utility with a high fixed monthly charge may invite several kinds of undesirable and even dangerous behaviors by consumers.

Risky connections in Delhi, India

The first of these is informal master-metering, where more than one household is served through a single meter. This can happen when houses are divided into a primary residence and an accessory dwelling unit (mother-in-law apartment). However, if the monthly fixed charge is low, the owner will normally have a second meter installed for the second dwelling so that both occupancies pay for their own electricity. These type of "ohana" (extended-family) units account for as much as 15% of the housing stock in parts of Hawaii.

The second is more dangerous: connecting multiple dwellings together with less-than-utility-grade wiring. This is very common in some countries, and creates safety risks for residents and reliability risks for the electric distribution system (see photo from India).

Third, high fixed monthly charges may result in some seasonal consumers completely disconnecting service during part of the year. This actually increases costs for utilities, since they must handle the customer service call twice. At the same time it inconveniences the consumer. The electric distribution system is unchanged during this period when service to individual customers is

2 Testimony of John Howat, National Consumer Law Center, Wisconsin PSC Docket No. 3270-UR-120.

3 For an explanation of how rate design and elasticity affects usage, see Lazar, J. (2013). *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed*, Appendix A. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6516

suspended. Some utilities have responded by imposing high reconnection charges when the customer initiates service, but this may also adversely affect rental properties where move-in / move-out changes of service are common, and often involve lower income consumers. As in other situations involving low-use customers, the electric distribution system is not changed by the coming or going of an individual consumer.

Principle: Customers Should Be Able to Connect to the Grid at Reasonable Cost

Based on the discussion in the early chapters of "Smart Rate Design for a Smart Future," we derived our first principle of electricity pricing:

A customer should be able to connect to the grid for no more than the cost of connecting to the grid: This should reflect only those costs to the system that the *addition* of the customer adds, such as billing and metering, not the distribution infrastructure.

The Foundation of Regulation Is the Prevention of the Exercise of Monopoly Power

The imposition of a fixed charge for the privilege of being a customer is almost non-existent in the competitive world. Oil refineries, hotels, airlines, and supermarkets have significant fixed costs, including building and equipment. Even their labor costs do not vary directly with sales volumes. But all of these recover all their fixed and variable costs through volumetric prices. In a competitive environment, it is essentially impossible to charge a customer for the privilege of being a customer. In fact, we find quite the opposite — special discounts offered to attract new customers, to try to build a business relationship that will then continue over time.

The original purpose of public service company regulation was to prevent the exercise of pricing power by businesses that had a local monopoly over service. The earliest of these were the regulations imposed on overnight lodging in medieval England, while the modern framework of utility regulation in the United States began with railroads and associated businesses.

Munn vs. Illinois

One landmark case involved a grain elevator operator who owned the only facilities that farmers could use to load their products onto the railroads. The alternative was to haul the grain a long distance, not an easy proposition in the era of horse-drawn wagons.

In Munn v. Illinois, the US Supreme Court ruled that businesses "affected with the public interest" could be subject to regulation by states. In that decision, the Court stated:

> *"In countries where the common law prevails, it has been customary from time immemorial for the legislature to declare what shall be a reasonable compensation under such circumstances, or perhaps more properly speaking, to fix a maximum beyond which any charge made would be unreasonable."*[4]

This principle evolved over time to give state utility regulators the authority to fix the specific tariffs for electric service, and most state laws require that these be "fair, just, and reasonable" or similar subjective legislative criteria. This prevented the exercise of monopoly pricing power over consumers who had no other utility available to them.

Where utilities are allowed to impose high fixed monthly charges, this becomes an exercise of monopoly pricing power. As Charles Cicchetti, former chairman of the Wisconsin Public Service Commission, recently stated with respect to the Wisconsin Electric Power Company proposal to recover its generation, transmission, and distribution investment-related costs in fixed monthly charges:

> *"WEPCO invokes mostly outdated and previously rejected logic in an attempt to convince the Commission to let it use its utility monopoly and mostly very limited customer choice to force customers to absorb risks in an unjust and unreasonable manner, which is contrary to economic and public policy objectives."*[5]

Imparting to Natural Monopolies the Pricing Discipline That Is Imposed By Competitive Markets

Another important role of utility regulation is to impart to natural monopolies (as electric distribution utilities are generally categorized) the same pricing discipline that competitive firms experience, so that they endeavor to minimize costs and maximize customer satisfaction. If utilities are allowed to recover their system costs in fixed charges for the privilege of being a customer, much of this discipline is lost. Conversely, if they recover their costs in

4 Munn v. Illinois, 94 U.S. 113 (1877)

5 Testimony of Charles Cicchetti, Wisconsin Public Service Commission, Docket No. 05-UR-107 (2014), p. 25.

the per kWh price, they must compete with alternatives to electricity consumption from the utility, including energy efficiency and customer self-generation. This discipline helps to hold costs down for all consumers.

Universal Service Policies

Universal access to electricity service has long been recognized as desirable for social, health, safety, and other reasons. In the United States, electric utilities expanded service to urban areas and to large businesses in the late years of the 19th century, but at the time of the great depression most rural areas were still without electric service because the cost to expand distribution systems was not profitable.

The Congress responded by creating the Rural Electrification Administration (REA, now the Rural Utility Service or RUS) to help expand electricity to rural areas.[6] Lyndon Johnson's first campaign for Congress in 1936 had as a key campaign issue to secure electricity service for rural Texas; he came from an area now served by the Pedernales Electric Cooperative, headquartered in Johnson City. The REA provided interest-free loans and grants to help make universal service to smaller communities possible. The electrification of these communities was viewed as important to help these communities survive and prosper.

The United Nations Secretary General's Advisory Group on Energy and Climate Change[7] has set a goal to extend basic electricity service to 99% of the population of the world. The definition of "basic" service includes provision of lighting (so that students can continue their studies after sunset) and refrigeration (to reduce food-borne illness). The level of consumption is 50 kWh per month per person to meet these basic needs. In the United States and other developed countries, the "basic" needs level of service is higher than the developing world figure used by the UN, on the order of 300–400 kWh/month/household.

SFV rate design strikes directly at universal service, because it makes electricity service, even for the most basic and essential uses, unaffordable to low-income households. It does this (even if they are densely located in urban areas where distribution costs are very low), by averaging their cost of service with suburban and rural areas where per customer distribution costs are very different. In effect, under SFV pricing, low-income households are made to subsidize higher-income, higher-usage households.

Regulate Price Where Competitive Market Does Not Exist to Set Price

Finally, a key role of utility regulation is to set prices where a competitive market does not exist to impose prices on suppliers. Electricity distribution service remains such an area of commerce in nearly all communities in the United States. The role of the regulator is to implement prices equivalent to what would be charged by a competitive market, were one present.

As we discuss below, in other competitive markets the monthly charge for "connection to the system" is usually zero, and even where it is greater than zero it is normally very small.

The Relationship Between Fixed Costs and Fixed Charges

Utilities often argue that the majority of their costs are fixed, and extrapolate from this that these fixed *costs* should be recovered in fixed *charges*. This is lacking in both economic foundation and accounting principles:

Just because a cost is fixed in the short run does not mean it should be recovered in a fixed charge.

Utilities often assert that most of their costs are "fixed" and should be recovered in fixed charges. While interest and depreciation expense are fixed in the short run, virtually every other cost is variable even in the short run.

Even if a cost is "fixed" it does not mean it should be recovered in a fixed charge. Investments in power plants are made to provide a supply of electricity, and the costs should be recovered in proportion to how much of that production a customer uses (this is discussed in Chapter V of the main text, when considering the various dimensions of usage that are measured and priced). Transmission facilities are built to connect remote power plants to the communities needing power, and are essentially an alternative to building those power plants directly in the community.

The decision to build distribution systems is made where

6 For detail on the RUS, see: http://www.rd.usda.gov/about-rd/agencies/rural-utilities-service.

7 Energy for Sustainable Future, the Secretary-General Advisory Group on Energy and Climate Change, United Nations Industrial Development Organization, 2010.

there is a sufficient market to justify the cost, not based on how much each individual consumer will use or how many consumers will be served. Nearly every utility has a “line extension policy” that dictates where the utility will build distribution facilities, and under what circumstances the customers seeking service must pay for the line extension. A circuit serving 10 large customers, each using 100,000 kWh/month will attract investment as easily as a circuit serving 1,000 customers each using 1,000 kWh/month. All of these investments have elements of fixed costs, but this does not mean they should be recovered in fixed charges.

Utility labor costs are often thought of as fixed in the short-run, but during the 2008 economic crisis some utilities reduced staffing by as much as 10% to preserve earnings in the face of sharp reductions in industrial activity. In a financial crisis, maintenance is deferred, customer service quality is impaired, and even administrative costs are cut.

There is a sound argument that individual customers should pay the direct costs of their customer-specific costs. Historically, this has been interpreted by many utility regulators as the cost of meters, service drops, meter reading, billing, and collection. These costs are normally calculated in the range of $5–$10/month, but even the meter reading, billing, and collection costs are variable costs that are a function of how often bills are rendered. The additional cost of smart meters is justified by many benefits beyond the simple measurement of usage (see Chapter IV of the main text), and this additional cost is not properly considered customer-related. The primary reason for monthly billing is not to collect the $5–$10/month in customer-specific costs, but to collect the $50–$150/month in electricity usage charges; if usage were very small, quarterly billing would be adequate. Thus, even these monthly billing costs are related to usage.

A recent posting by Severin Borenstein, professor and director emeritus of the University of California Energy Institute, addresses this in detail, and utterly discredits the suggestion that fixed costs should translate into fixed charges. He states:

> *But the mere existence of system wide fixed costs doesn’t justify fixed charges. We should get marginal prices right, including the externalities associated with electricity production. We should use fixed charges to cover customer-specific fixed costs. Beyond that, we should think hard about balancing economic efficiency versus fairness when we use additional fixed charges to help address revenue shortfalls.*[8]

A cost-based fixed charge recovers those costs that vary with the number of customers.

The debate in rate design as to what costs belong in the monthly customer charge often follows on the related debate in cost allocation as to which costs are customer-related in nature. While some regulators have allowed distribution infrastructure costs to be classified as customer-related, most have directed that only customer-specific costs be classified as customer-related, and it follows that only those customer-specific costs be included in the monthly fixed customer charge.

These issues were heavily debated in most states during the PURPA proceedings of 1978–1982, and most states resolved these issues in favor of a narrow definition of customer-related costs. Most regulators have adhered to these principles since.

For example, the Illinois PUC recently ruled that the mere fact that costs are “fixed” in some short-term sense should not guide rate design:

> *“The Companies’ proposed SFV rate design diverges from cost-causation, substituting its “fixed” cost designation for cost causation as the determinative allocator. …*
>
> *“By failing to send proper price signals, the Companies’ proposed rate design denies consumers who conserve the benefit of their actions, and punishes customers who are frugal. The proposed SFV charges are indifferent to efficiencies in usage and demand. In contrast, the Commission has recognized that lower monthly customer charges and higher volumetric charges can advance energy use conservation and efficiency policy objectives by providing a greater price signal.*
>
> *“The Commission finds that Staff’s and Intervenor’s arguments in favor of assigning demand-based costs to volumetric charges are consistent with energy efficiency and the avoidance of cross subsidies.”*[9]

Calculated Example

It is relatively straightforward to calculate an example of how customer-related costs translate into customer charges that are cost-based, and recover only customer-specific costs in per-customer fixed charges; see Table D-3.

8 Borenstein, S. (2014, November 3). *What’s So Great About Fixed Charges?* See https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/

9 Illinois Commerce Commission, People’s Gas, Docket 14-0224, 2015.

Table D-3

Calculated Example

Calculation of Per-Customer Costs	
Service Drops	$100,000
Meters	$100,000
Subtotal Rate Base	$200,000
Allowed Return With Taxes	12%
Allowed Return	$24,000
Depreciation Expense	$8,000
Subtotal Capital Costs	$32,000
Meter and Service Maintenance	$5,000
Billing and Collection Costs	$25,000
Subtotal Operating Costs	$30,000
Total Customer-Related Costs	$62,000
Customers Serviced	1,000
Annual Cost/Customer	$62.00
Monthly Cost/Customer	$5.17

How Competitive Markets Address The Fixed Cost/Fixed Charge Issue

A principal purpose of regulation is to impose on natural monopolies the same discipline that competitive firms face in setting unregulated prices. Every business has costs that are fixed in the short run, and every profitable firm recovers these in a manner that enables them to attract customers and price their product effectively to address competitive pressure. In almost all cases, the result is that fixed costs are recovered volumetrically.

Gasoline

American consumers spend about the same proportion of their income on gasoline as on electricity, but gasoline trades in a competitive, largely unregulated market. The entire gasoline supply stream involves immense investments that are at least as "fixed" as electric utility distribution systems. Oil wells involve huge drilling expense. Oil tankers are very expensive. Oil refineries cost billions of dollars to build. The pipeline network that brings the crude oil to the refineries, and the product pipelines that move finished products from the refineries to the communities where it is consumed are fixed assets. Even the local oil terminal, tanker trucks, and service stations or mini-marts involve extensive investment.

Figure D-1

Unbundled vs. Bundled Pricing for Gasoline

Crude Oil	$2.237
Tanker to Refinery	$0.114
Refinery Capital	$0.213
Refinery Operating	$0.235
Product Pipeline	$0.113
Terminal Rack	$0.023
Truck to MiniMart	$0.114
MiniMart Profit	$0.217
State Taxes	$0.349
Federal Taxes	$0.184

These costs are all recovered in a single price per gallon of gasoline at the pump, and no attempt is made to impose a separate "subscription" charge from the usage charge, or to separate out (itemize or unbundle) the cost of gasoline. Customers compare stations based on the ultimate price per gallon (and other factors, including brand, convenience, and real or perceived differenced in quality) on a basis that combined all fixed and variable costs into a single price per gallon.

Think about which of the two pricing approaches in Figure D-1 is most useful to you in making a gasoline purchase decision comparing two gas stations.

Groceries

Consumers spend even more of their budget on groceries than on gasoline or electricity. Like gasoline, the grocery supply chain is immense, bringing products from around the globe to a supermarket near where we live. Supermarkets do not charge admission fees and, except in dense urban areas, provide free parking completely independent of how much a customer spends. However, prices are slightly different depending on how the customer "connects to the grocery grid." A large chain like Kroger, Albertson's, or Wal-Mart has lower prices than a neighborhood mini-mart — but the customer incurs the cost of traveling to the supermarket to secure those lower prices. In essence, they bear the cost of connecting to the "grocery grid" at a more centralized point. But in both cases the fixed (and variable) costs of the grocer are reflected in the per-unit prices of their products. We discuss membership stores such as Costco and Sam's Club separately.

Membership Discount Stores: They DO Charge to "Be a Customer"

Membership stores like Costco and Sam's Club DO charge a "membership fee" for customers to gain admission. They do this for a simple reason: to reduce the number of "shoppers" versus "buyers" in their stores, in order to increase the volume of product that can be sold from a given store size.

In essence, these stores provide consumers an opportunity to "connect to the grid" at a wholesale level, rather than a retail level.

However, even for these stores, the membership fee reflects a very small portion of annual revenues, about 2%–4%; for an electric utility that would equate to a customer charge of $2/month to $4/month, based on an average monthly bill nationally of about $100/month.

But even the membership fee may be rebated. Costco has two membership tiers, $55/year and $110/year for "Executive" membership. The Executive membership comes with a 2% annual rebate on purchases — and is marketed by Costco to their larger consumers. Most Executive members receive rebates that approximate or exceed their annual membership dues.

In addition, virtually every product available from a membership store is also available (generally in smaller package sizes) at supermarkets or discount stores like Target and Wal-Mart, without a membership fee. Consumers who do not buy enough to justify the membership fee can easily avoid it, unlike electric consumers who do not have a realistic alternative to the electric utility service.

The electricity service equivalent would be if a customer built their own connection to the utility at the primary voltage level — and then would pay a much lower price (as large industrial consumers do) for their service. Customers that connect to the grocery grid at the "distribution" level of their neighborhood supermarket pay slightly higher prices than at warehouse stores.

Hotels

Large hotels often involve tens of millions of dollars of investment (into the billions for destination mega-resorts.) They recover these costs on a per-room per-day basis. But they employ sophisticated pricing models in doing so, varying pricing based on demand for rooms, season of the year, and with discounts for large-volume buyers (convention rates). We will not defend the lack of transparency in hotel pricing, but will note that search tools like Hotwire, Priceline, and Trivago have made it possible for individual consumers to receive many of the pricing advantages that larger buyers achieve.

The dynamic pricing for hotel rooms (and for airline tickets and rental cars) has been the foundation on which many proposals for electric dynamic pricing (see discussion in main paper) have been based.

Making Electricity Pricing Comparable

To make electricity pricing comparable to that for gasoline, groceries, or hotel rooms would not actually be very difficult. First, different prices based on where the customer connects to the grid would be developed; most utilities already have these, with separate rates for customers served at secondary, primary, and transmission voltage. Next, the prices for all electricity would be on a volumetric basis, but differentiated by time of day, season of year, geographic zone, and with dynamic elements that would raise prices when electricity is scarce and discount it when it is at risk of being wasted. This is discussed in Chapter V of the main tect.

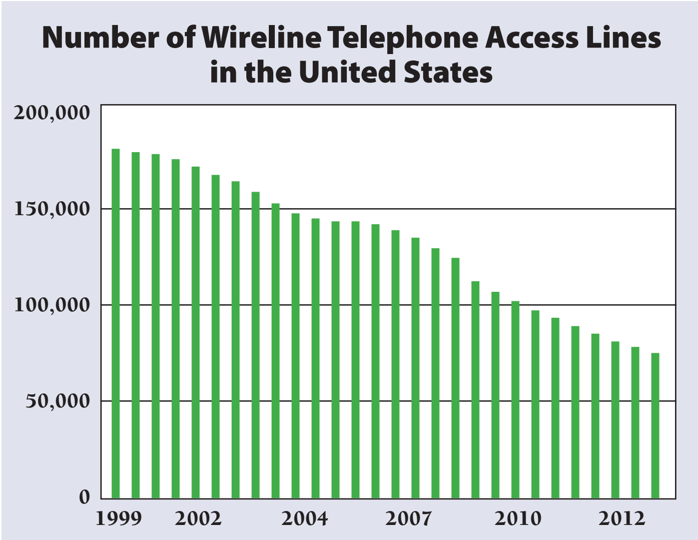
The Experience with Telecom

Some analysts point to the telecommunications industry as an example in which consumers pay high monthly fixed charges for cellular "plans" and pricing is not volumetric. This is somewhat inaccurate, and the history of telecommunications deregulation is instructive for some potential pitfalls of high fixed-charge pricing for electricity.

Prior to 1980, telephone companies were integrated providers of local and long-distance phone service. Each long-distance call contributed a few cents per minute to the local carrier, and this allowed the per-month rates for basic telephone service to be very low.

When long-distance competition began in the 1980s, customers needed to use "dial-around" systems to reach competitive services. They would dial a local number to a competitive carrier, dial in additional information, and the competitive carrier would connect the call to the destination city and place a local call there to make the connection. Large companies installed sophisticated "least

Figure D-2



cost routing" systems to do this automatically. These had a modest impact on the financial health of local exchange carriers (traditional phone companies).

Later, federal policy required local exchange carriers to allow customers to choose their long-distance carrier. At that time, an "access charge" was imposed at the federal level to compensate local carriers for a portion of the lost revenues, "termination fees" were imposed so the receiving phone company received compensation for delivering the connection at the receiving end, and long-distance prices dropped sharply.

This proved inadequate to replace all of the lost margins, and local exchange carriers petitioned state regulators to sharply increase their monthly fixed charges. In many parts of the county, the combined effect of the local rate design and the federal access charges raised the monthly fixed charge for telephone service from about $6/month to $30/month or more. The result has been dramatic: local exchange carriers have lost more than half of their customer access lines.

Does this mean that customers are making and receiving fewer calls? Certainly not. Or are less able to transmit documents, or access data services? Hardly. All of these services have moved to competitive suppliers, and in parts of the country local exchange carriers are abandoning territory and facing financial distress. The local exchange carriers have effectively priced themselves out of traditional markets with high fixed charges.

Some of these carriers have been successful by building fiber optic systems to deliver high-speed Internet, television, and other content. By bundling services together, they have built viable business models. But other competitors have entered the market to provide low-cost basic telephone service.

- Tracfone provides cellular service for as little as $7/month, including voice, text, voicemail, and even Internet service — on a pay-per-minute basis, with approximately 1,000 minutes per year provided on an "annual plan" available through discounters. Other prepaid cellular companies include Virgin Mobile, Cricket, and Consumers Cellular.
- Straighttalk provides both cellular and voice-over-internet-protocol (VOIP) service, with unlimited calling for $10–$15 per month, marketed through Wal-Mart stores.
- Magic-Jack provides VOIP service for as little as $50/year with unlimited calling for those with broadband Internet access.
- Skype provides local and long-distance unlimited VOIP service for as little as $25/year, including video communication and video conferencing.
- Federally subsidized "lifeline" phone service for low-income households is migrating from fixed line to cellular service, in part to avoid high fixed-line charges.

Many telephone services are now offered on a fully bundled "all-you-can-eat" basis. These are attractive to high-use customers, and sometimes chosen by less knowledgeable small users. But competitive firms offering service with very low fixed fees are widely available.

Addressing Revenue Stability Concerns

Electric utilities companies are concerned about rate design in part because under traditional volumetric rate design declining sales results in declining profits. This is a real issue. A study prepared on one electric utility showed that a 2% decline in sales would result in a 24% reduction in net earnings.

There are many ways to address revenue stability issues, and high monthly fixed charges are probably the worst option from a customer impact perspective. A discussion of several alternatives follows.

Table D-4

Impact on Earnings of Sales Decline for Illustrative SW Electric Utility[10]

% Change in Sales	Revenue Change		Impact on Earnings		
	Pre-tax	After-tax	Net Earnings	% Change	Actual ROE
5.00%	$9,047,538	$5,880,900	$15,780,900	**59.40%**	17.53%
4.00%	$7,238,031	$4,704,720	$14,604,720	**47.52%**	16.23%
3.00%	$5,428,523	$3,528,540	$13,428,540	**35.64%**	14.92%
2.00%	$3,619,015	$2,352,360	$12,252,360	**23.76%**	13.61%
1.00%	$1,809,508	$1,176,180	$11,076,180	**11.88%**	12.31%
0.00%	$0	$0	$9,900,000	**0.00%**	11.00%
-1.00%	-$1,809,508	-$1,176,180	$8,723,820	**-11.88%**	9.69%
-2.00%	-$3,619,015	-$2,352,360	$7,547,640	**-23.76%**	8.39%
-3.00%	-$5,428,523	-$3,528,540	$6,371,460	**-35.64%**	7.08%
-4.00%	-$7,238,031	-$4,704,720	$5,195,280	**-47.52%**	5.77%
-5.00%	-$9,047,538	-$5,880,900	$4,019,100	**-59.40%**	4.47%

Revenue Regulation

Most utility regulators set prices for electricity, and let revenues float as sales volumes deviate from assumed levels. An alternative, revenue regulation (or "decoupling"), works differently: the regulator sets an allowed level of revenue and periodically allows minor adjustments in prices to ensure the utility recovers the allowed revenue. More than half of the US states have employed some form of this, as shown in Figure D-3.

Incentive Regulation

A number of regulators have adopted various forms of incentive regulation to reward utilities for strong efforts to achieve energy efficiency. These "performance-based regulation" (PBR) frameworks can reward any number of desired utility performance indicators, including lower sales per customer. It is also possible to combine a PBR mechanism with decoupling.[11]

Weather Normalization

Utility sales vary with weather and, for many, this is the single largest driver of month-to-month net income. A weather adjustment simply adjusts prices periodically, usually monthly, to address abnormal weather. These are relatively common for natural gas utilities.

Reserve Accounts

Some regulators, primarily municipal utility authorities, create specific reserve accounts to be drawn on when sales are below expected levels (or sometimes when expenses are above expected levels). These are quite common for hydroelectric-based utilities, where there are wet years and dry years and the power supply costs can vary dramatically.

All of these approaches leave the basic utility rate design unaffected. The total cost of service can still be reflected in an easy-to-understand volumetric price. The utility's revenue is augmented when sales fall below expected levels. Other approaches are less desirable from an energy efficiency and customer impact perspective, but may also provide utility revenue stability.

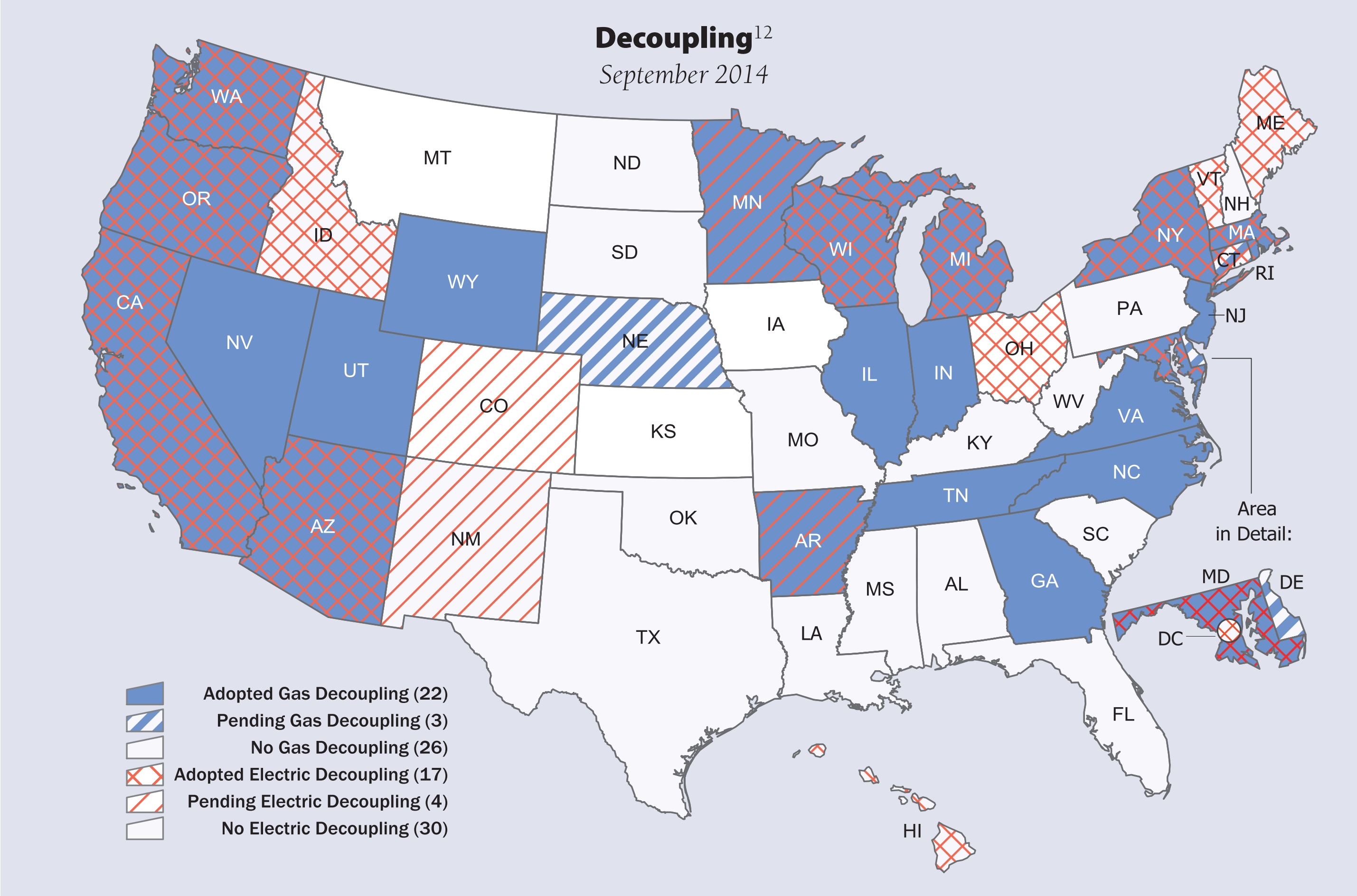
Demand Charges

Some utilities have proposed implementing demand charges on residential and small commercial consumers to recover a portion of revenues based on the customer's highest hourly usage during a month. These types of rate designs are common for large commercial consumers. These are less appropriate for small users, because a customer's highest hourly usage may be a poor predictor of their monthly or annual usage, or of the demand they place on the grid during peak hours and therefore the costs incurred to serve them. For example, an apartment dweller may have an electric water heater, coffee pot, hair dryer, and range all operating for a short period in the morning, creating a short-duration peak demand of 10 kilowatts, when their average consumption is less than 1

10 Presentation of W. Shirley, Arizona Corporation Commission, April 15, 2010.

11 See, for example, *Performance-Based Regulation for EU Distribution Utilities.* (2014). Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/7332

Figure D-3



kilowatt. The utility gets the benefit of all of the units in that apartment building having diversity in their loads — meaning that all of the appliances are not running at the same time throughout the building.

Because apartments typically have lower demands than single-family homes, this rate form is less hostile to small users than a high fixed charge. But demand charges normally bill each customer based on their individual demand, not on their contribution at the time of the system peak, the circuit peak, the class peak, or even the peak of the customers sharing the same line transformer. In this way, they are inefficient rate forms. (See discussion of residential demand charges in Chapter IV.)

The only distribution system component that is sized to individual customer demands is the final line transformer; therefore, the only cost that can be justified to be included in a demand charge based on individual customer peaks is that of the transformer. The remainder of the system is sized based on the combined coincident demand of many customers on the circuit or the entire grid during extreme periods. While a demand charge based on the contribution of each customer to the system coincident peak demand would be one way to recover these costs, it would be poorly understood and could create highly volatile bills. A time-varying energy charge is a more easily understood way to achieve the same goal.

Connected Load Charges

Several utilities impose separate monthly fixed charges on customers of different size, often measured by the size of the electrical panel being served. This provides utilities with a stable amount of revenue each month to cover the cost of the grid connection, and also imposes higher charges on customers with larger potential usage. If the connected load charge is limited to the costs that are sized to individual customers — the line transformer and service

12 Source: Natural Resources Defense Council, http://www.nrdc.org/energy/decoupling/.

Table D-5

Manitoba Hydro Residential Electric Rate		
Standard Residential Tariff No. 2014-01		
Monthly Basic Charge:	NOT Exceeding 200 Amp	$7.28
	Exceeding 200 Amp	$14.56
Plus **Energy Charge:**		7.381c/kWh
Note: Minimum monthly bill is the basic charge		

drop — then it meets the first rate design criteria, that a customer should be able to connect to the grid for no more than the cost of connecting to the grid.

An example of this type of charge is the residential rate design of Manitoba Hydro in Canada. Their rate design is intended to capture customers with electric heat, who impose much higher capacity costs on the distribution transformers that serve them. Table D-5 shows the Manitoba Hydro rate.

Summary

This appendix has addressed the concept of high monthly fixed charges to recover electric utility distribution costs. This is a hotly contested rate design issue, and it is inevitable that different regulatory bodies will reach different conclusions. The key principles that we have sought to detail are:

- Customers should be able to connect to the grid for no more than the cost of connecting to the grid: Only very local distribution costs, such as the final line transformer and service drop, are "fixed costs" of individual customers connecting to the grid.
- Competitive industries do not impose fixed charges on customers, but instead bundle all costs into a per-unit cost; since one purpose of regulation is to impose on monopoly utilities the pricing discipline that the market imposes on competitive businesses, regulators should seek to minimize fixed charges in electricity tariffs.
- Other types of fixed charges, such as residential demand charges, are generally inappropriate, and should give way to time-differentiated energy charges.

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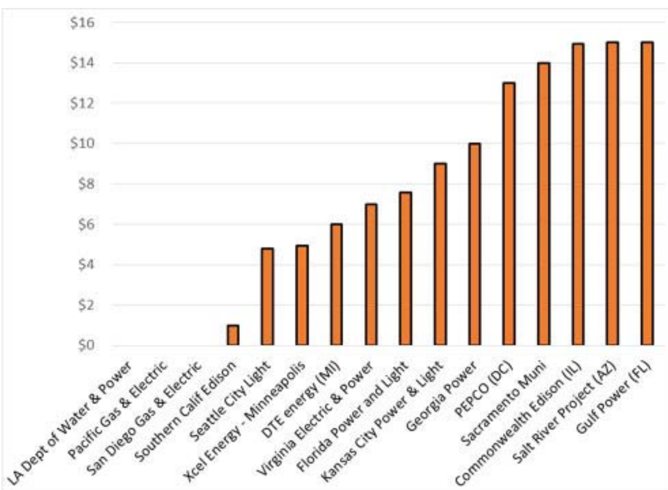
What's so Great about Fixed Charges?

Posted on November 3, 2014 by Severin Borenstein

There's a lot of talk in California these days about imposing fixed monthly charges on residential electricity bills. The large investor-owned utilities in California have small or no fixed charges,[1] instead collecting all of their revenue from households through usage-based charges, called volumetric pricing. (And those volumetric prices increase steeply with your monthly usage, the "increasing-block pricing" approach that I discussed in September.)

Interestingly, one of the three natural gas distribution companies in California has a fixed charge, but the other two don't (SoCal Gas has a charge that is about $5/month. Feel free to chime in if you know how this difference came to be.) Most other electric utilities in the U.S. do charge some fixed monthly fee for being hooked up to the electric grid.



Fixed monthly charges at regulated and muni utilities (randomly selected outside CA)

Fixed charges are often justified based on the utility having fixed costs. The connection seems logical at first glance, but when you look closer it's more complicated.

Fixed costs fall roughly into two types: customer-specific and systemwide. When having one more customer on the system raises the utility's costs regardless of how much the customer uses – for instance, for metering, billing, and maintaining the line from the distribution system to the house – then a fixed charge to reflect that additional fixed cost the customer imposes on the system makes perfect economic sense. The idea that each household has to cover its customer-specific fixed cost also has obvious appeal on ground of fairness or equity.

Customer-specific fixed costs from things like metering, billing, electric drop to house

But much of the utility fixed costs that are being discussed are systemwide – such as maintaining the distribution networks in residential neighborhoods. These costs wouldn't change if one customer were to drop off the system. In other words, running the system as a whole has certain unavoidable costs and someone has to pay them. There isn't much guidance, based on economics or equity, about who should pay, because there is no "cost causation" as it is termed in the utility world. In particular, the statement I have heard a number of times recently that "the utility should cover fixed costs with fixed charges" has no basis in economics when it comes to system fixed costs.

Before we discuss how to pay for system fixed costs, let's step back and remember where economics does provide a valuable guide, that is, in setting the price of an incremental or marginal kilowatt-hour. The price for a marginal kilowatt-hour should reflect the full "societal" marginal cost of providing that electricity, meaning that it should include the industry's marginal production costs plus the marginal externality costs imposed on others outside the production process, like the cost of greenhouse gases that are released. The idea is that if you don't place a value on the good that is at least as great as the full cost of producing it (including the pollution it creates), then society shouldn't allocate resources to produce it for you.

If you don't think about it too hard, you might conclude that if the marginal (or volumetric) price just covers marginal cost, then what is left over is fixed costs, so fixed charges "should" cover fixed costs.

But there are at least three good reasons to think harder about it.

First, the marginal cost that the *utility* faces is less than the full marginal cost it imposes on society when it produces electricity because the utility does not have to pay the full social cost of the pollution it produces — including NOx, particulates, and greenhouse gases.[2]

If the utility charges a price that covers the full marginal cost including all the externalities, but doesn't itself actually have to pay for those externalities, then it generates extra revenue. That revenue can go towards covering fixed costs. That lowers the fixed charge necessary to cover costs while at the same time setting appropriate marginal prices.[3]

Second, as everyone who studies electricity markets knows (and even much of the energy media have grown to understand), the marginal cost of electricity generation goes up at higher-demand times, and all generation gets paid those high peak prices. That means extra revenue for the baseload plants above their lower marginal cost, and that revenue that can go to pay the fixed costs of those plants, as I discussed in a paper back in 1999.

The same argument goes for transmission lines, where price differentials between locations mean that the transmission line generates revenue above its marginal cost (which is effectively zero), and can go to pay the fixed costs of transmission lines. In fact, the fixed costs of generation and transmission should generally be covered without resorting to fixed monthly charges.

The same is not true, however, for distribution costs. Retail prices don't rise at peak times and create extra revenue that covers fixed costs of distribution. That creates a revenue shortfall that has to be made up somewhere. Likewise, the cost of customer-specific fixed costs don't get compensated in a system where the volumetric charge for electricity reflects its true marginal cost.

But unlike customer-specific fixed costs, there isn't a strong fairness or economic efficiency argument for recovering fixed distribution costs – which are not customer-specific — through a fixed monthly charge.

Programs subsidizing high-efficiency light bulbs, refrigerators and washing machines may be a great idea, but they still create fixed costs that ratepayers have to cover

And then there are sunk losses from the mistakes of the past, such as expensive nuclear power plants and high-priced contracts signed during the California electricity crisis. And don't forget ongoing expenses that are not directly part of the electric utility function, like energy efficiency. Someone has to pay for those subsidies on new refrigerators and clothes washers.[4]

That brings us to the third reason to think hard about fixed charges: fairness and distributional considerations. If customer A uses 10 times more electricity than customer B, should they pay the same share of the system fixed costs? And, by the way, customer A is *on average* wealthier than customer B. My informal poll suggests most people think customer A should pay more.

But any approach that is based on usage amounts to raising the volumetric price further, after we have already raised it to reflect the real externalities. Doing that encourages inefficient substitution away from electricity. Yes, there can be such a thing as too much energy efficiency investment (take a look at the cost of retrofitting windows). Nor does it really help society when high marginal prices incent households to install solar just to shift fixed costs to others. And, of course, Max recently blogged about how high marginal electricity prices discourage EVs.

And that's where it can make sense to resort to fixed monthly charges to cover at least part of the shortfall. Fixed charges may be the least bad way for utilities to balance their books without setting volumetric electricity prices so high that they unreasonably distort behavior.

But the mere existence of systemwide fixed costs doesn't justify fixed charges. We should get marginal prices right, including the externalities associated with electricity production. We should use fixed charges to cover customer-specific fixed costs. Beyond that, we should think hard about balancing economic efficiency versus fairness when we use additional fixed charges to help address revenue shortfalls.

I tweet energy news articles, and the occasional research article, nearly daily @BorensteinS

——————

[1] PG&E and SDG&E have no fixed charge, SCE's is $0.99/month. All three have a small minimum bill, less than $10, which is binding on extremely few customers.

[2] What's that you say? that California utilities already have to cover their GHG emissions in the state's cap-and-trade market? *Oh please.* First, the utilities are given free permits to cover most of their emissions. Second, the regulatory agency (CPUC) has said publicly that it will not allow GHG costs to raise residential rates. And, finally, do you really think the current price in the cap-and-trade market of $12/ton – an amount that will lead to virtually zero change in production or consumption behavior — covers anything like the full cost of the GHG emissions? It's less than one-third of the U.S. government's estimate of the true externality cost (which I think is likely still too low).

[3] Of course, if we ever get to actually charging polluters for their emissions, then this source of extra revenue to the utility will go away. That will still be a happy day for me.

[4] Please, save the comments arguing that energy efficiency programs pay for themselves. They may save society as much or more in energy resource costs as they cost the utility, but when it comes to rate making, the money for those programs comes from ratepayers, and energy efficiency programs don't justify a volumetric rate increase on economic grounds.

Our residential rates as of January 2017

Residential Service (RS-1, RSL-1, RSL-2)

Customer charge	$8.76 per month
Energy charge	
First 1,000 kWh	6.736¢ per kWh
All kWh above 1,000	8.098¢ per kWh
Fuel charge	
First 1,000 kWh	3.377¢ per kWh
All kWh above 1,000	4.377¢ per kWh
Asset Securitization Charge	
All kWh	0.287¢ per kWh

Residential Service Time of Use (RST-1) (Closed to new customers as of 2/10/10.)

Customer charge	$16.19 per month*
Energy charge	
On-peak	17.122¢ per kWh
Off-peak	2.615¢ per kWh
Fuel charge	
On-peak	4.573¢ per kWh
Off-peak	3.245¢ per kWh
Asset Securitization Charge	
All kWh	0.287¢ per kWh

*For most residential customers. Where an advance special meter payment is made, the charge is $8.76.

Residential Seasonal Service (RSS-1)
You can reduce your customer charge from $8.76 per month to $4.58 per month if you are gone for at least three months during the billing periods of March through October and do not use more than 210 kWh per month (or 7 kWh per day). All other charges as stated in otherwise applicable rate schedules still apply.

Lighting Service (LS-1)
This service is available from dusk to dawn with various automatically controlled light fixtures.

Fixture and maintenance charge	Depends upon fixture type
Customer charge (per line of billing)	
Metered	$3.42 per month
Unmetered	$1.19 per month
Energy charge	2.584¢ per kWh
Fuel charge	3.494¢ per kWh
Asset Securitization Charge	0.044¢ per kWh

Billing Adjustments (BA-1)
All the energy charges listed above include the following amounts for energy conservation (ECCR), environmental (ECRC) and purchased power capacity (CCR) which includes the nuclear cost recovery clause:

Residential – RS-1, RSS-1, RSL-1, RSL-2 and RST-1:

ECCR	0.317¢ per kWh
ECRC	0.151¢ per kWh
CCR	1.294¢ per kWh

Lighting – LS-1:

ECCR	0.105¢ per kWh
ECRC	0.144¢ per kWh
CCR	0.203¢ per kWh

30956-I-0115

All rates effective with January 2017 billing

Important information about a change to Duke Energy Florida's 2017 residential rates

Safe, reliable, cleaner energy at a fair price is important to you - our customers. It is important to us, too.

Duke Energy Florida's electric rates are set by the state. As a regulated utility, Duke Energy Florida's rates cover the costs necessary to produce and deliver reliable power to the company's 1.7 million customers who rely on electricity as part of their daily lives.

The Florida Public Service Commission has approved Duke Energy Florida's annual price changes, related to costs for fuel, purchased power, nuclear, environmental controls and energy efficiency measures, starting with January 2017 billing. Residential customers will see rate changes resulting in an increase of less than 4 percent or $4.39 per month on a 1,000-kilowatt-hour (kWh) bill.

The efficiency upgrades to the Hines Energy Complex, which serves all Duke Energy Florida customers, have been delayed. Therefore, the 49 cents per 1,000-kilowatt-hour (kWh) increase to residential customer electric rates previously approved by the Florida Public Service Commission to go into effect in November billing for the first part of the project will be postponed until later in 2017. You will receive more information about this project prior to it going into service.

Duke Energy has also received Florida Public Service Commission approval to recover the costs related to purchasing the Osprey Energy Complex starting with February 2017 billing. The addition of the clean natural gas plant will help support long-term growth and future energy needs in a cost-effective manner. Residential customers will see an additional increase of about 1 percent or $1.45 per 1,000 kWh starting with February billing. After the February change the monthly residential bill for 1,000 kWh will be $117.10.

In March, we anticipate a change to the Asset Securitization Charge. While the total dollars collected in rates will stay relatively constant, the customer rate may change, at least twice a year, due to fluctuations in sales. The required formula-based true-up process adjusts for the difference between the estimated and actual amounts collected. We have previously projected the charge will drop slightly in March. More information will be provided to you at that time. We work hard on behalf of our customers to ensure safe, reliable, cleaner energy 24/7. We are leveraging innovative technology across our Florida service territory to upgrade the energy grid, improve reliability and help customers become more energy efficient - all while keeping energy costs below the state and national averages.

You can help reduce your electric bill by managing your energy use. Duke Energy provides free home energy audits and tips for customers. Visit duke-energy.com or call 1.877.574.0340.

DUKE ENERGY®

Breakdown of the new 2017 monthly bill statement

This bill belongs to a sample customer who uses 1,500 kWh of electricity each month.

Notice how we've presented the **January** 2017 residential rates so you can clearly see the costs for the first 1,000 kWh as compared to the costs per kWh above 1,000. To help you better understand the bill, we've provided the definitions below of the items included in most residential bills.

```
    RSL-1/2  091 Residential Load Management
(1) BILLING PERIOD..01/01/17 TO 01/30/17   30 DAYS
    CUSTOMER CHARGE                                              8.76
(2) ENERGY CHARGE
      FIRST 1000 KWH           1000 KWH @  6.736¢               67.36
(3)   ABOVE 1000 KWH            500 KWH @  8.098¢               40.49
    FUEL CHARGE
      FIRST 1000 KWH           1000 KWH @  3.377¢               33.77
(4)   ABOVE 1000 KWH            500 KWH @  4.377¢               21.89
    ASSET SECURITIZATION CHARGE
                               1500 KWH @   .287¢                4.31

    TOTAL ELECTRIC COST                                                 176.58

(5) ENERGYWISE HOME (Load Management) CREDIT                            11.50CR

(6) GROSS RECEIPTS TAX                                                    4.23

(7) MUNICIPAL FRANCHISE FEE   6%                                         10.16

(8) MUNICIPAL UTILITY TAX    10%                                         13.43

    TOTAL CURRENT BILL                                                  192.90
```


1. **Customer charge:** A fixed monthly amount to cover the cost of providing service to your location. This charge is applicable whether or not electricity is used.
2. **Energy charge:** All the costs, other than fuel, involved in producing and distributing elctricity.
3. **Fuel charge:** This includes the actual cost of fuel used to produce electricity. The company's two largest fuel sources are natural gas and coal. Fuel costs are passed through from fuel suppliers to customers with no profit to the company. This charge is adjusted annually to reflect changes in the cost of fuel.
4. **Asset Securitization Charge:** The result of a bond issuance process put in place to lower the cost of the company's retired nuclear plant. This saves customers more than $800 million over the next 20 years – or approximately $2 per month per 1,000 kWh – compared to traditional cost recovery methods.
5. **EnergyWise® Home program credit:** EnergyWise Home is a free program that offers qualified participants a credit of up to $147 a year depending on their monthly energy usage and the appliances enrolled in the program.
6. **Gross receipts tax:** Collected in accordance with Florida state statutes, this tax is assessed on all electric public utilities and paid directly to the state. Duke Energy Florida does not keep these tax monies.
7. **Franchise fee:** This is a fee that we collect to compensate communities for using their rights of way. The entire fee is sent back to the local community; Duke Energy Florida does not keep any franchise fees. Fees vary by community.
8. **County/municipal utility tax:** In accordance with state law, a county/municipality may levy a tax on the purchase of electricity within that area. This tax is paid directly to your county/municipality. Duke Energy Florida does not keep any of these taxes.

For more information about Duke Energy rates, visit **duke-energy.com/rates**.

RESIDENTIAL SERVICE

RATE SCHEDULE: RS-1

AVAILABLE:

In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU.

SERVICE:

Single phase, 60 hertz at available standard distribution voltage. Three phase service may be furnished but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$7.87
Non-Fuel Charges:	
Base Energy Charge:	
First 1,000 kWh	5.562 ¢ per kWh
All additional kWh	6.562 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Residential Load Control Program (if applicable)	See Sheet No. 8.217
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$7.87

TERM OF SERVICE:

Not less than one (1) billing period.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

ELECTRIC SERVICE TARIFF:

RESIDENTIAL SERVICE SCHEDULE: "R-22"

GEORGIA POWER
A SOUTHERN COMPANY

PAGE	EFFECTIVE DATE	REVISION	PAGE NO.
1 of 2	With Bills Rendered for the Billing Month of January, 2016	Original	2.10

AVAILABILITY:

Throughout the Company's service area from existing lines of adequate capacity.

APPLICABILITY:

For all domestic uses of a Residential Customer in a separately or commonly metered dwelling unit. A Residential Customer hereunder is defined in the Company's Rules and Regulations for Electric Service.

TYPE OF SERVICE:

Single or three phase, 60 hertz, at a standard voltage.

MONTHLY RATE:

WINTER - For the Billing Months of October through May
Basic Service Charge...$10.00
First 650 kWh…………………………………………………………………………5.6582¢ per kWh
Next 350 kWh…………………………………………………………………………4.8533¢ per kWh
Over 1000 kWh…………………………………………………………………………4.7641¢ per kWh

SUMMER - For the Billing Months of June through September
Basic Service Charge...……………………………………………………..……….....……………..$10.00
First 650 kWh…………………………………………………………………………5.6582¢ per kWh
Next 350 kWh…………………………………………………………………………9.3983¢ per kWh
Over 1000 kWh…………………………………………………………………………9.7273¢ per kWh

Minimum Monthly Bill: $10.00 Basic Service Charge plus Environmental Compliance Cost Recovery, plus Nuclear Construction Cost Recovery, plus Demand Side Management Residential Schedule, plus Municipal Franchise Fee.

ENVIRONMENTAL COMPLIANCE COST RECOVERY:

The amount calculated at the above rate will be increased under the provisions of the Company's effective Environmental Compliance Cost Recovery Schedule, including any applicable adjustments.

NUCLEAR CONSTRUCTION COST RECOVERY:

The amount calculated at the above rate will be increased under the provisions of the Company's effective Nuclear Construction Cost Recovery Schedule, including any applicable adjustments.

DEMAND SIDE MANAGEMENT SCHEDULE:

The amount calculated at the above rate will be increased under the provisions of the Company's effective Demand Side Management Residential Schedule, including any applicable adjustments.

SCHEDULE: "R-22"

PAGE	EFFECTIVE DATE	REVISION	PAGE
2 of 2	With Bills Rendered for the Billing Month of January, 2016	Original	2.10

FUEL COST RECOVERY:

The amount calculated at the above rate will be increased under the provisions of the Company's effective Fuel Cost Recovery Schedule, including any applicable adjustments.

MUNICIPAL FRANCHISE FEE:

The bill calculated under this tariff will be increased under the provisions of the Company's effective Municipal Franchise Fee Schedule, including any applicable adjustments.

SENIOR CITIZEN - LOW INCOME ASSISTANCE:

Qualifying customers certified by the Company will be eligible for a monthly bill discount of up to $18.00 monthly at their primary residence. This discount will be applied to the customer's pre-fuel monthly bill amount. To qualify, the customer must be 65 years of age or older with total household income of 200% of the federal poverty level or less per year, provided that the electric service account is individually metered and in said customer's name. There shall be no net credits nor shall there be any carry-over credits.

MULTIPLE SERVICE:

Where two or more dwelling units are served through a common meter, the Basic Service Charge and each appropriate kWh block in the above monthly rate shall be multiplied by the number of separate dwelling units so served.

The minimum monthly bill under this option shall be $10.00 Basic Service Charge times the number of dwelling units served plus Environmental Compliance Cost Recovery, plus Nuclear Construction Cost Recovery, plus Demand Side Management Residential Schedule, plus Municipal Franchise Fee. Billing under this provision shall be designated "R-22-M".

BUDGET BILLING OPTION:

The Customer may be offered the option of being rendered a budget bill which has the effect of leveling the Customer's monthly billing amount. Details of this billing option are on file in each Company office and with the Georgia Public Service Commission. This option is available only for separately metered dwelling units.

TERM OF CONTRACT:

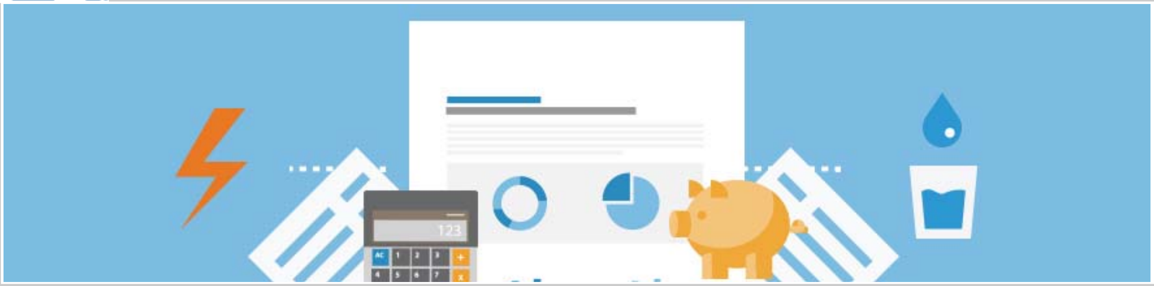
One (1) year, unless customer selects another Residential tariff for which they qualify.

GENERAL TERMS & CONDITIONS:

The bill calculated under this tariff is subject to change in such an amount as may be approved and/or amended by the Georgia Public Service Commission under the provisions of applicable riders and other schedules.

Service hereunder is subject to the Rules and Regulations for Electric Service on file with the Georgia Public Service Commission.

Docket No. 160186-EI
Residential Rates
Exhibit KRR-6, Page 6 of 10



My Account

- Add, Move, or Stop Service
- Billing and Payment Options
- Commercial Forms and Policies
- Create a jea.com Account
- New Customer Information
- Protecting You and Your Information
- Residential Forms and Policies
- Understand My Bill
  - High Bills
  - **Rates**
    - SmartSavings
    - 2016 Electric Rate Restructuring
    - Commercial Electric Rates
    - Electric Rate Comparison
    - Electric Rates Definitions
    - Tariff Schedule
    - Water Rate Comparison
    - Water Rates Definitions
  - Bill Breakdown
  - Electric Bill Estimator
  - Explanation of Bill
  - Fuel Credit
  - Meter Reading
  - Net Metering Bill Breakdown
  - Water Bill Estimator

Rates

Utilities across the country are facing challenging times - increasing fuel prices, increasing environmental regulations, and extreme weather. JEA is faced with some of those same challenges, but we are doing everything we can to keep rates low and stable.

Currently our prices are below average for the state. And you may not realize it, but your JEA bill is about 12% less today than it was six years ago, when adjusted for inflation. In 2015, customers received a credit on their bill for the third year in a row. We were able to gain substantial savings on the fuel we use to generate electricity, so we are again returning those savings to you.

January 2016 Fuel Charge Decrease

On January 19, 2016 the JEA Board approved a Fuel Charge decrease of $6.85 per megawatt hour with an effective date of February 1, 2016. This reduction translates to a 5.56% decrease in the electric portion of a 1,000 kWH a month residential customer's bill and lowers JEA electric rates to the 2008 level. Commercial customers should receive a 6-9% decrease depending on rate class.

Read the transcript

If you are unsure of what the terms below mean, please reference our Glossary of Electric Terms or our Glossary of Water and Sewer Terms.

Residential electric rates

This rate is designed for all residential customers. There is no demand charge, as it is incorporated into the energy charge. Customers in this class include single family homes, individually metered apartments, and some common areas at apartment complexes and home owner associations.

Basic Monthly Charge	Energy Rate per kWh	Fuel Rate per kWh	Environmental Rate per kWh	Total Rate per kWh
$5.50	$0.06988	$0.03250	$0.00062	$0.10300

Plus the following taxes and fees as determined by the city or county:

Duval County 3% Franchise Fee 2.5641% Gross Receipts Tax 10% Public Service Tax	**Atlantic Beach** 6.5574% Franchise Fee 2.7322% Gross Receipts Tax 5% Public Service Tax
Baldwin 6.5574% Franchise Fee 2.7322% Gross Receipts Tax 10% Public Service Tax	**Clay County** 6.5574% Franchise Fee 2.7322% Gross Receipts Tax 4% Public Service Tax on usage over 500 kWh
Orange Park 6.5574% Franchise Fee 2.7322% Gross Receipts Tax 10% Public Service Tax	**St. Johns County** 2.5641% Gross Receipts Tax

Residential water, sewer and irrigation rates

General Service electric rates (Small commercial)

General Service Demand electric rates (Large commercial)

General Service Large Demand electric rates (Industrial)

Commercial water, sewer and irrigation rates

Multi-family water, sewer, and irrigation rates

JEA is a municipal or community-owned utility. Our rates are designed to cover the cost of operating your electric, water and sewer business and to pay down the debt for money borrowed to expand and improve the pipes and wires we use to send electricity and water to your home, and for the pipes to collect and remove sewer from your home. Our rates also cover current state and federal regulations. There are additional regulations that could have an impact on rates in the next decade, because compliance with these regulations could cost JEA up to $1 billion.

Utility service is a complicated and costly business. We want you to know that we work hard to be responsible stewards of your business and the environment, while bringing you the most reliable service possible.

Effective Dates of Rates:

- Electric Base: January 1, 2012
- Electric Fuel: November 15, 2016
- Water and sewer: October 1, 2012

LAKELAND ELECTRIC
POWERED FOR LIFE

Nineteenth Revised Sheet No. 6.0
Cancels Eighteenth Revised Sheet No. 6.0

RATE SCHEDULE RS
RESIDENTIAL SERVICE

Available:

In all territory served by Lakeland Electric

Applicable:

To all electric service provided to single family homes, mobile homes, or apartments where such energy usage is exclusively for residential purposes. Also, for energy used to service commonly-owned facilities in condominium and cooperative apartment buildings subject to the following requirements.

1. 100% of the energy used is exclusively for the Customer's benefit.
2. None of the energy is used in any endeavor which sells or rents a commodity or provides service for a fee.
3. Each point of delivery will be separately metered and billed.
4. A responsible legal entity is established as the Customer to whom a bill can be rendered.
5. Beginning January 1, 2016 new solar electric systems interconnected with Lakeland Electric shall take service under Rate Schedule RSD. Existing customers as of this date may maintain service under this rate scheduled through December 31, 2025.

Character of Service:

A-C; 60 Hertz; single phase 3 wire; 120/240 volts or 120/208 volts.

Limitation of Service:

Standby service or resale not permitted under this rate schedule.

Net Rate per Month:

Customer Charge:	$9.50
Energy Charge:	
0 to 1,000 kWh	5.085¢ per kWh
1,001 to 1,500 kWh	5.646¢ per kWh
above 1,500 kWh	6.207¢ per kWh

Minimum Bill: Customer charge, plus Adjustments.

Adjustments:

Fuel charge, as contained in Schedule BA-1
City Utility Tax or Surcharge, taxes, surcharges, and fees as contained in Schedule BA-2
Environmental Compliance Cost Charge as contained in Schedule BA-3
Smart Grid Project Implementation as contained in Schedule BA-5

Payment:

Net bills are due when rendered and are delinquent thirty (30) days after the billing date.

Terms and Conditions:

1. All Service hereunder will be supplied at one location through one point of delivery and measured through one meter.
2. Service hereunder is subject to the rules and regulations for electric service as adopted by Lakeland Electric from time to time and on file with the City Clerk.

RS

RESIDENTIAL ELECTRIC SERVICE
RATE SCHEDULE RS

Availability:

For residential customers within OUC service area in individually metered single family dwelling units occupied as a domestic residence where electricity is used exclusively for residential purposes.

Monthly Rate:

Customer Charge:		$8.00
Non-Fuel Base Charge at:	First 1,000 kWh	**6.418¢** per kWh
	All Additional kWh	**7.418¢** per kWh

Fuel Charge: See Sheet No. 5.010

Gross Receipts Tax:

In accordance with Section 203.01 of the Florida Statutes a gross receipts tax is applicable to electric sales charges.

Municipal Tax and Orange County Public Service Tax:

The monthly rate charges plus all adjustments are subject to the City of Orlando Municipal Utility Tax within the city and to the Orange County Public Service tax outside the city. The Municipal Utility Tax and the Orange County Public Service tax do not apply to amounts for fuel above a cost of 0.638¢ per kWh.

Minimum Bill:

Customer Charge

Terms of Payment:

See “Terms of Payment” on Sheet No. 5.600.

Limitation of Service:

Not available for resale or partial, standby, and supplemental service.

City of Tallahassee

Residential Electric Rates

Standard Rate Plan

Monthly Fees	
Customer Charge	\$7.41 - single phase; \$25.94- three phase
Usage Rates	
Energy Rate (non-fuel)	\$0.06857 per kWh
Fuel and Purchase Power Charge Rate (ECRC)	\$0.02974 per kWh
Effective Billing Rate	\$0.09831 per kWh

Optional Nights & Weekends Pricing Plan See more information

Monthly Fees	
Customer Charge	\$7.41 - single phase; \$25.94- three phase
Off-Peak Usage Rates (7 p.m. to 7 a.m. weekdays, weekends and holidays)	
Energy Rate (non-fuel)	\$0.02886 per kWh
Fuel and Purchase Power Charge Rate (ECRC)	\$0.02587 per kWh
Effective Off-Peak Billing Rate	\$0.05473 per kWh
On-Peak Usage Rates (7 a.m. to 7 p.m. weekdays, Monday-Friday)	
Energy Rate (non-fuel)	\$0.16839 per kWh
Fuel and Purchase Power Charge Rate (ECRC)	\$.0.3688 per kWh
Effective Peak Billing Rate	\$0.20527 per kWh

> Return to main utility rates page

Detailed information about City of Tallahassee Utilities rate applicability or availability, discounts, penalties, etc. can be found at the Municipal Code Corporation (MCC).

Rates listed are applied to all utility bills rendered on and after January 1, 2017.

Contact Info

Utility Customer Service
435 North Macomb Street
Tallahassee FL 32301
850-891-4968
Maps and Directions
Contact Us

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	:	
	:	
Proposed general increase in gas rates.	:	**14-0224**
(tariffs filed February 26, 2014)	:	
	:	
The Peoples Gas Light and Coke Company	:	
	:	
Proposed general increase in gas rates.	:	**14-0225**
(Tariffs filed February 26, 2014)	:	**(Consol.)**

ORDER

January 21, 2015

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STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	:	
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Proposed general increase in gas rates.	:	**14-0224**
(tariffs filed February 26, 2014)	:	
	:	
The Peoples Gas Light and Coke Company	:	
	:	
Proposed general increase in gas rates.	:	**14-0225**
(Tariffs filed February 26, 2014)	:	**(Consol.)**

ORDER

I. INTRODUCTION/ PROCEDURAL HISTORY

On February 26, 2014, North Shore Gas Company ("North Shore" or "NS") filed with the Illinois Commerce Commission ("Commission"), pursuant to Section 9-201 of the Public Utilities Act (the "Act" or "PUA") (220 ILCS 5/9-201), the following revised tariff sheets: ILL. C.C. No. 17, Title Sheet and ILL. C.C. No. 17, Sheet Nos. 6-10, 18, 27, 42, 58, 66, 77, 89, 114, 124, 135.1. This tariff filing embodied a proposed general increase in gas service rates, revisions to the service classifications, riders and terms and conditions of service. The tariff filing was accompanied by direct testimony, other exhibits, and other materials required under Parts 285 and 286 of Title 83 of the Illinois Administrative Code (the "Code"), 83 Ill. Adm. Code Parts 285 and 286.

On February 26, 2014, The Peoples Gas Light and Coke Company ("Peoples Gas", "Peoples" or "PGL") filed with the Commission, pursuant to Section 9-201 of the Act, the following revised tariff sheets: ILL. CC. No. 28, Title Sheet and ILL. C. C. No. 28, Sheet Nos. 5-9, 16, 19, 28, 42, 59, 68, 78, 95, 120, 140, 151.1. This tariff filing embodied a proposed general increase in gas service rates and revisions of other terms and conditions of service. The tariff filing was accompanied by direct testimony, other exhibits, and other materials required under Parts 285 and 286 of the Code.

Notices of the proposed tariff changes reflected in these rate filings were posted in North Shore's and Peoples Gas' (the "Utilities" or "Companies") business offices and published in secular newspapers of general circulation in the Utilities' respective service areas, as evidenced by publishers' certificates, in accordance with the requirements of Section 9-201(a) of the Act and the provisions of 83 Ill. Adm. Code Part 255.

The Commission issued a Suspension Order for North Shore's tariff filing on March 19, 2014, which suspended the tariffs to and including July 25, 2014, and further initiated Docket 14-0224. On July 9, 2014, the Commission issued a Resuspension Order that suspended these tariffs to, and including, January 25, 2015. However the deadline for Commission action is January 20, 2015.

The Commission issued a Suspension Order for Peoples Gas' tariff filing on March 19, 2014, which suspended the tariffs to and including July 25, 2014, and initiated Docket 14-0225. On July 9, 2014, the Commission issued a Resuspension Order that suspended these tariffs to, and including, January 25, 2015.

On April 1, 2014, North Shore and Peoples Gas each filed motions for protective orders in their respective Dockets, pursuant to Section 4-404 of the Act and 83 Ill. Adm. Code §§200.190 and 200.430. On April 14, 2014, the Administrative Law Judges ("ALJs") held an initial status hearing and, received the oral motion of Commission Staff ("Staff") to consolidate these cases and also orally approved a case schedule and data request response time schedule. On April 15, 2014, the Attorney General of the State of Illinois (the "Attorney General" or "AG") filed a response to North Shore's and Peoples' motions for a protective order. On May 7, 2014, the Utilities each filed a motion for entry of case management plan and schedule, pursuant to Section 10 101.1 of the Act and 83 Ill. Adm. Code §§ 200.190, 200.370, and 200.500. On August 8, 2014, Staff filed a motion to strike portions of the rebuttal testimony of the Utilities' witness Ms. Christine M. Hans and NS-PGL Ex. 26.3 in its entirety. On August 20, 2014, the Utilities filed a response to Staff's motion to strike portions of the rebuttal testimony of Ms. Christine M. Hans and NS-PGL Ex. 26.3. On August 27, 2014, Staff filed a reply in support of its motion to strike portions of the rebuttal testimony of Ms. Christine M. Hans and NS-PGL Ex. 26.3. On September 2, 2014, the ALJs denied Staff's motion to strike portions of the rebuttal testimony of Ms. Christine M. Hans and NS-PGL Ex. 26.3.

On September 4, 2014, Staff filed a motion for leave to file instanter the rebuttal testimony of Daniel G. Kahle, Dianna Hathhorn, and Janis Freetly. On September 10, 2014, the ALJs granted Staff's motion for leave to file instanter. On September 15, 2014, the Attorney General filed a motion to strike certain testimony of Utilities' witness Ms. Debra Egelhoff. On September 17, 2014, the Utilities filed a response to the Attorney General's motion to strike certain testimony of Utilities' witness Ms. Debra Egelhoff. On September 19, 2014, the Administrative Law Judges granted in part and denied in part the Attorney General's motion to strike certain testimony of Utilities' witness Ms. Debra Egelhoff. On October 17, 2014, Staff filed a motion for administrative notice of Peoples Gas' Qualifying Infrastructure Plant Surcharge Rider ("Rider QIP") information Sheet No. 9 and its supporting schedules and future Rider QIP informational Sheet Filing Nos. 10, 11, and 12 and their supporting schedules. On October 27, 2014, the Utilities filed a motion to correct the transcript of September 22-23, 2014 hearings. On October 29, 2014, the Utilities filed a response to Staff's motion for administrative notice relating to Rider QIP information sheets and supporting schedules. On October 29, 2014, the AG filed a motion to correct the transcript of September 22-23, 2014 hearings. On October 29, 2014, the AG filed a Motion to re-open the record of the People of the State of Illinois and admit into evidence a data request response from Docket No. 14-0496. *Wisconsin Energy Corporation, Integrys Energy Group, Inc., Peoples Energy, LLC, The Peoples Gas Light and Coke Company, North Shore Gas Company, ATC Management Inc., and American Transmission Company LLC*, Docket No. 14-0496. On October 30, 2014, the AG filed a revised version of that motion. On October 31, 2014, the Utilities filed a response to the AG's October 30th motion. On November 3, 2014, Staff filed a reply in support of its motion for administrative notice. On November 3, 2014, the AG filed a reply in support of its October 30th motion.

On November 5, 2014, the Administrative Law Judges granted Staff's motion for administrative notice with certain additional rulings. On November 5, 2014, the Administrative Law Judges granted the AG's October 30th motion. On November 10, 2014, the Administrative Law Judges granted motions to correct the transcript filed by the AG and the Utilities.

Petitions to Intervene

Petitions to Intervene were filed or appearances were entered on behalf of the AG; the Citizens Utility Board ("CUB"); the Retail Energy Supply Association ("RESA"); Merchandise Mart, the University of Illinois, Abbot Laboratories, Inc., AbbVie, Inc., and Ford Motor Company (collectively the "IIEC"); the Environmental Law and Policy Center ("ELPC"), (collectively, the AG and ELPC are "AG-ELPC") and the City of Chicago (the "City"), (collectively, the City, CUB and IIEC are "City-CUB-IIEC" or "CCI").

The Evidentiary Hearing

The evidentiary hearing was held September 22, 2014 and September 23, 2014, at the offices of the Commission in Chicago, Illinois. At the evidentiary hearings, the Utilities, Staff, and certain Intervenors entered appearances and presented testimony. The following witnesses testified on behalf of the Utilities: Dennis M. Derricks, Assistant Vice President, Regulatory Affairs, Integrys Business Support, LLC, North Shore and Peoples Gas (NS Exhibit ("Ex.") 1.0, PGL Ex. 1.0, NS-PGL 17.0, NS PGL Ex. 33.0); Lisa J. Gast, Manager, Financial Planning and Analysis, Integrys Business Support, LLC (NS Ex. 2.0, PGL Ex. 2.0, NS-PGL Ex. 18.0, NS-PGL Ex. 34.0); Paul R. Moul, Managing Consultant, P. Moul & Associates (NS Ex. 3.0, PGL Ex. 3.0, NS-PGL Ex. 19.0, NS-PGL Ex. 35.0); Kevin R. Kuse, Senior Load Forecaster, Integrys Business Support, LLC (NS Ex. 4.0, PGL Ex. 4.0); Christine M. Gregor, Director, Operations Accounting, North Shore and Peoples Gas, Integrys Business Support, LLC (NS Ex. 5.0, PGL Ex. 5.0 REV, NS-PGL Ex. 20.0); Sharon Moy, Rate Case Consultant, Regulatory Affairs, Integrys Business Support, LLC (NS Ex. 6.0, PGL Ex. 6.0, NS-PGL Ex. 21.0, NS-PGL Ex. 36.0); John Hengtgen, Consultant, Hengtgen Consulting, LLC (NS Ex. 7.0, PGL Ex. 7.0, NS-PGL Ex. 22.0 REV, NS-PGL Ex. 37.0); Mark Kinzle, General Manager, District Field Operations, North Shore Gas Company (NS Ex. 8.0, NS-PGL Ex. 31.0, NS-PGL Ex. 45.0); David Lazzaro, General Manager, District Field Operations, The Peoples Gas Light and Coke Company (PGL Ex. 8.0 2nd REV, NS-PGL Ex. 23.0 2nd REV, NS-PGL Ex. 38.0); John J. Spanos, Senior Vice President, Valuation and Rate Division, Gannett Fleming, Inc. (NS Ex. 9.0, PGL Ex. 9.0); Noreen E. Cleary, Assistant Vice President, Total Compensation, Integrys Energy Group, Inc. (NS Ex. 10.0, PGL Ex. 10.0, NS PGL Ex. 24.0); John P. Stabile, Tax Director, Integrys Business Support, LLC (NS Ex. 11.0, PGL Ex. 11.0, NS-PGL Ex. 25.0 REV, NS-PGL Ex. 39.0); Christine M. Hans, Manager, Benefits Accounting, Integrys Business Support, LLC (NS Ex. 12.0, PGL Ex. 12.0, NS-PGL Ex. 26.0, NS-PGL Ex. 40.0); Tracy L. Kupsh, Director, Operations Accounting IBS, Integrys Business Support, LLC (NS Ex. 13.0, PGL Ex. 13.0, NS-PGL Ex. 27.0, NS-PGL Ex. 41.0); Joylyn C. Hoffman Malueg, Rate Case Consultant – Regulatory Affairs, Integrys Business Support, LLC (NS Ex. 14.0, PGL Ex. 14.0, NS-PGL Ex. 28.0, NS-PGL Ex. 42.0); Debra

E. Egelhoff, Manager, Gas Regulatory Policy, Integrys Business Support, LLC (NS Ex. 15.0, PGL Ex. 15.0 REV, NS-PGL Ex. 29.0 REV, NS-PGL Ex. 43.0 REV); Thomas L. Puracchio, Manager, Gas Storage, Integrys Business Support, LLC (NS Ex. 16.0, PGL Ex. 16.0, NS-PGL Ex. 30.0, NS-PGL Ex. 44.0); James G. Robinson, General Manager – Customer Relations, Integrys Business Support, LLC (NS-PGL Ex. 32.0, NS-PGL Ex. 46.0).

The following witnesses testified on behalf of Staff: Dianna Hathhorn, Accountant, Accounting Department, Financial Analysis Division, Illinois Commerce Commission (Staff Ex. 1.0, Staff Ex. 6.0), Daniel Kahle, Accountant, Accounting Department Financial Analysis Division, Illinois Commerce Commission (Staff Ex. 2.0, Staff Ex. 7.0); Janis Freetly, Senior Financial Analyst, Finance Department, Financial Analysis Division, Illinois Commerce Commission (Staff Ex. 3.0, Staff Ex. 8.0); William R. Johnson, Economic Analyst, Rates Department, Financial Analysis Division, Illinois Commerce Commission (Staff Ex. 4.0, Staff Ex. 9.0), Brett Seagle, Gas Engineer, Energy Engineering Program, Safety and Reliability Division, Illinois Commerce Commission (Staff Ex. 5.0, Staff Ex. 10.0).

The AG's witnesses were: David J. Effron, Consultant (AG Ex. 1.0, AG Ex. 7.0); David E. Dismukes, PH.D., Consulting Economist, Acadian Consulting Group (AG Ex. 2.0 Corrected ("C"), AG Ex. 8.0); Roger D. Colton, Principal, Fisher Sheehan & Colton, Public Finance and General Economics (AG Ex. 4.0C, AG Ex. 10.0); Sarah Pickett, Administrative Assistant, Center for the Advancement of Science Education, Museum of Science and Industry (AG Ex. 5.0); Nathaniel Doromal, a software engineer in the finance industry (AG Ex. 6.0).

AG-ELPC's witness was: Scott J. Rubin, Consultant (AG/ELPC Ex. 3.0, AG/ELPC Ex. 9.0).

IIEC's witnesses were: Brian C. Collins, Consultant and Associate, Brubaker & Associates, Inc. (IIEC Ex. 1.0, IIEC Ex. 3.0); Amanda M. Alderson, Consultant, Brubaker & Associates, Inc. (IIEC Ex. 2.0).

City-CUB-IIEC's witness was: Michael P. Gorman, Consultant and Managing Principal, Brubaker & Associates, Inc. (City-CUB-IIEC Jt. Ex. 1.0, City-CUB-IIEC Jt. Ex. 2.0).

The above references to testimony are intended to include the attachments thereto, whether given separate exhibit numbers or not. All parties were given the opportunity to cross-examine witnesses. On November 10, 2014, the ALJs marked the record "Heard and Taken".

Rulings on Motions

A status hearing was held April 14, 2014, where Staff made a motion to consolidate these Dockets, as noted above. On April 14, 2014, after considering all of the parties' arguments, the ALJs entered a Protective Order for these dockets. On April 14, 2014, the ALJs issued a notice of schedule. On August 11, 2014, the ALJs granted Staff's motion to consolidate these dockets. On September 2, 2014, the ALJs denied Staff's motion to strike portions of the rebuttal testimony of Ms. Christine M. Hans and NS-PGL

Ex. 26.3. On September 10, 2014, the ALJs issued a notice of ALJ's ruling granting Staff's motion for leave to file instanter the rebuttal testimony of Daniel G. Kahle, Dianna Hathhorn, and Janis Freetly.

On September 19, 2014, the ALJs issued a notice of ALJ's ruling granting in part and denying in part the AG's motion to strike certain testimony of Utilities' witness Ms. Debra Egelhoff. On November 5, 2014, the Administrative Law Judges granted Staff's motion for administrative notice, with certain additional rulings. On November 5, 2014, the Administrative Law Judges granted the AG's October 30th motion.

<u>Post-Hearing Briefs</u>

On October 21, 2014, the Utilities, Staff, the AG, City-CUB, City-CUB-IIEC, ELPC, and IIEC, each filed Initial Briefs ("Init. Br." or "IB"). On November 6, 2014, the Utilities, Staff, the AG, City-CUB, City-CUB-IIEC, ELPC, and IIEC each filed Reply Briefs ("Rep. Br." or "RB"). On November 7, 2014, per direction of the ALJs, the Utilities submitted a draft Proposed Order.

On December 5, 2014, the ALJs issued their Proposed Order. On December 16, 2014, Briefs on Exceptions ("BOE") were filed by the Utilities, Staff, the AG, City-CUB-IIEC, ELPC, and IIEC. On December 23, 2014, Reply Briefs on Exceptions ("RBOE") were filed by Utilities, Staff, the AG, City-CUB-IIEC, and ELPC. This Order considers all of the positions and arguments set out in the briefs on exceptions and reply briefs on exceptions listed above.

II. TEST YEAR (UNCONTESTED)

The Utilities proposed calendar year 2015, the twelve months ending December 31, 2015, as the test year. NS Ex. 6.0 at 5; PGL Ex. 6.0 at 5. The Utilities submitted evidence that the forecasted 2015 test year data were based on careful analyses and appropriate adjustments. NS Ex. 5.0 at 4-5; NS Ex. 6.0 at 5; PGL Ex. 5.0 REV at 4-5; PGL Ex. 6.0 at 5. The proposed test year is reasonable NS Ex. 6.0 at 2; PGL Ex. 6.0 at 2, is uncontested, and is approved.

III. REVENUE REQUIREMENT

A. North Shore

<u>Companies' Position</u>

North Shore's final proposed base rate revenue requirement (as revised in its rebuttal testimony) is $88,181,000, or $89,778,000 if costs recovered as Other Revenues ($1,597,000) are included, and North Shore states that its proposed revenue requirement is just and reasonable based on the testimony and other exhibits in evidence. *e.g.*, NS-PGL Ex. 21.0 at 3; NS PGL Ex. 36.0 at 3, fn. 1; NS-PGL Ex. 21.1N, lines 1, 5, 10, and 11, column (''col.")[G].

At each of the direct and rebuttal testimony stages, North Shore presented pie charts and additional information showing the drivers of the net changes in their distribution costs of service and revenues forecasted for 2015 versus the levels expected in 2015 under the rates approved in the Companies' 2012 rate cases. NS-PGL IB at 10.

Staff's Position

The revenue requirement schedules attached to Staff's Initial Brief use the Peoples Gas' surrebuttal revenue requirement, and North Shore's rebuttal revenue requirement, as their starting point. To the extent that Staff's proposed adjustments were rejected or only partially accepted by the Companies and reflected in the Companies surrebuttal revenue requirement, Staff's proposed adjustments are shown either in total or in part as an adjustment to the Companies' surrebuttal revenue requirement. Staff's proposed adjustments that were accepted in total by the Companies and therefore are reflected in the Companies' surrebuttal position are not shown as an adjustment on Staff's Initial Brief Revenue requirement schedules.

Staff recommends a revenue requirement of $86,798,000 as reflected on page 1 of Appendix A to Staff's Initial Brief. Staff recommends an increase to base rates of $3,460,000 and an increase of $84,000 to other revenues for a total increase of $3,544,000 (4.26%). Staff's overall recommended increase is $2,980,000 less than the $6,524,000 increase requested by North Shore in rebuttal.

AG's Position

Notwithstanding their objection to the uncertainty of the 2015 test year as described in part III.C below, the AG recommends reducing the proposed revenue requirement (see NS-PGL Ex. 36.0 at 3:56) of North Shore Gas by $7.506 million, as shown at AG Exhibit 7.1, page 1 (Schedule DJE NS A) at the bottom of the "AG Proposed Adjustments" column. This proposed adjustment is not meant to oppose (or support) any adjustment proposals offered by other parties in this proceeding on which the AG has not commented.

More generally the AG questions the propriety and need of a rate increase for either Company. As it considers the Companies' claims that they require significant rate increases, the Commission typically assesses the claimed needs of shareholders within the context of rate of return evaluation. The rate-making process under the Act, *i.e.*, the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. *Citizens Utility Board v. Illinois Commerce Comm'n*, 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995); *citing Camelot Utilities, Inc. v. Illinois Commerce Comm'n,* 51 Ill.App.3d 5, 10, 365 N.E.2d 312 (1977). In the landmark case *Bluefield Waterworks Improvement Co. v. Public Service Comm'n of West Virginia,* 262 U.S. 279 (1923), the U.S. Supreme Court established that a utility's rates should reflect the opportunity – not a guarantee – to earn a return on its used and useful property when a commission sets rates. The *Bluefield* Court further held that a utility has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. *Id.* The Court specified that the return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. *Id.* at 693. Investors holding interests in regulated public utilities understand that these companies are dedicated to serving the public and therefore, the investors' possible returns may be limited. *Id.* at 692-693.

Illinois courts have adopted the *Bluefield* standards and applied them to the regulation of utilities in Illinois: "'The rate making process under the act, *i.e.*, the fixing of just and reasonable rates[,] involves a balancing of the investor and the consumer interests.'" *Illinois Bell Telephone Co. v. Illinois Commerce Comm'n* (1953), 414 Ill. 275, 287, 111 N.E.2d 329, quoting *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944). Similarly, the Illinois Supreme Court earlier established that a just and reasonable rate must be less than the value of the service to consumers. *State Public Utilities Comm'n ex rel. City of Springfield v. Springfield Gas & Electric Co*., 291 Ill. 209, 216, 125 N.E. 891 (1919). The Appellate Court elaborated on this pronouncement in *Camelot Utilities, Inc. v. Illinois Commerce Comm'n*, 51 Ill.App.3d 5, 10, 365 N.E.2d 312 (1977), wherein the Court declared that it is the ratepayers' interest which must come first:

> The Commission has the responsibility of balancing the right of the utility's investors to a fair rate of return against the right of the public that it pay no more than the reasonable value of the utility's services. While the rates allowed can never be so low as to be confiscatory, within this outer boundary, if the rightful expectations of the investor are not compatible with those of the consuming public, it is the latter which must prevail.

Camelot Utilities, 51 Ill.App.3d at 10; *Citizens Utility Board v. Illinois Commerce Comm'n,* 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995).

As it balances the interests of Integrys Energy Group, Inc.'s ("Integrys") shareholders and the Companies' customers in this rate case, the Commission must consider the financial well-being of the customers these monopoly companies serve – just as it considers the claimed earnings requirements of investors. In so doing, the Commission should be mindful of the economic challenges facing low-income populations residing in the Companies' respective service territories. AG witness Roger Colton presents a thorough and detailed analysis demonstrating that a substantial proportion of Chicago-area ratepayers cannot afford to pay their natural gas bills even under current rates, let alone under the massive rate increases being proposed by the North Shore and Peoples utilities.

For example, the City of Chicago, which represents the entirety of Peoples' service territory, has 270,000 of its residents, or 10% of the City's population, living on income that is less than 50% of the Federal Poverty Level. More than 20% of the City's population lives at or below the Federal Poverty Level, while more than a third live on income below 150% of the Federal Poverty Level. Nearly half of all Chicago residents live with income below 200% of the Federal Poverty Level. AG Ex. 4.0 at 23-24.

Similarly, North Shore's service area has 80,000 people living at or below 200% of the Federal Poverty Level. Nearly as many people are in extreme poverty, below 50% of the Federal Poverty Level, (12,513) as live at the upper range of this population (13,217 between 175% and 200% of Federal Poverty Level). Nearly 30,000 people live below 100% of the Federal Poverty Level. Of all people in the North shore service territory, 14% live with income below 200% of the Federal Poverty Level. AG Ex. 4.0 at 24-25.

Unfortunately, the huge burden that these rate increase proposals could impose on North Shore and Peoples residential customer bases is not limited to those falling under official poverty definitions. Colton's testimony documents a "self-sufficiency income" standard for Chicago area households, using the self-sufficiency standards that were developed for Illinois by the Center for Women's Welfare at the University of Washington, based on periodic data-based analysis of the low-income and working populations throughout Illinois. AG Ex. 4.0 at 19. The self-sufficiency standard defines the level of income needed to maintain a minimum level of living without assistance. A person living on a self-sufficiency income does not live comfortably: he has no savings, spends nothing on recreation, does not make capital repairs to his housing or transportation and buys nothing on credit. While the 2014 Poverty Level for a three-person household is nearly $19,800 *per* year, the self-sufficiency standard is closer to $60,000 *per* year. So a person could have income three times the Federal Poverty Level, and still have inadequate income to be self-sufficient. AG Ex. 4.0 at 22-23. In 2009, the year in which the first self-sufficiency study was prepared for Illinois, the self-sufficiency wage ranged from a low of $23.97 *per* hour (West Side of Chicago) to a high of $29.31 *per* hour (DuPage County). The geographic area making up the North Shore and Peoples services territories have the highest self-sufficiency standards in the state of Illinois, *i.e.*, it takes more money to live a "no-frills" existence in these areas than anywhere else in the state. AG Ex. 4.0 at 22; AG Ex. 4.1, Schedule RDC-8.

The great difficulty which many people will face if the proposed rate increases and rate designs are approved is shown on Schedule RDC-12 of AG Ex. 4.1. With the median income in Chicago (below which level 50% of the population lives) at $47,653, at least 50% of Chicago's population lives below the self-sufficiency income for the North Side ($61,871), the West Side ($56,137) and the South Side ($56,267). AG Ex. 4.0 at 27. In the North Shore service territory, with the exception of one community, the median income for the lowest 20% of the population is not high enough to meet that region's self-sufficiency standard. In four of North Shore's communities the median income for the second lowest 20% of the population is a mere $30,000, and in five more North Shore communities the median income is between $30,000 and $50,000, well below the self-sufficiency standard. AG Ex. 4.0 at 28.

Given the harsh realities of the economic circumstances under which so many of North Shore and Peoples ratepayers live, it is hard to escape Colton's conclusion that a substantial number of these utility consumers cannot afford to pay their natural gas bills even under current rates. AG Ex. 4.0 at 28. Increasing rates pursuant to the North Shore/Peoples plan will make the unaffordability of natural gas delivery service not just a monthly risk but an inescapable reality for even more of these ratepayers.

Finally, Colton's examination of the North Shore/Peoples rate proposal impacts on low-use customers evaluated the risks facing Integrys relative to the burdens and risks facing customers described above. In order to examine whether the utilities had made an attempt to balance the interests of ratepayers and investors, during discovery in this proceeding the AG asked both North Shore and Peoples to provide the Attorney General's Office with each presentation or written materials provided as part of an agenda item made to the Integrys, North Shore or Peoples Board of Directors regarding low-income issues. The response provided by the utilities was that no such presentations, agenda items or materials existed. AG Ex. 4.0 at 29-30. Additionally, the AG asked the utilities to provide a copy of each presentation or agenda materials presented to the Integrys, North Shore or Peoples Board of Directors on customer service, credit or collection issues. The answer was the same: no such materials existed. AG Ex. 4.0 at 30. The financial risks facing its customers do not appear to have played a significant role in the utilities preparation of these rate increase requests.

Statements made by Integrys, the parent company of North Shore and Peoples, to the investment community, however, show considerable attention was given to the financial risks facing the companies and their investors. Company witness Moul stated that he did not engage in a balancing of interests in setting his common equity return recommendation, explaining that he considered only "investors" assessment of overall risk," which, he stated, includes "business risk" and "financial risk." AG Ex. 4.0 at 30, citing PGL Ex. 3.0 at 3, 7. Moul further testified that both utilities are riskier because they are smaller, have high operating ratios, have greater variability in earned returns and have experienced a decline in internally-generated funds, AG Ex. 4.0 at 31, citing PGL Ex. 3.0 at 8-10, and therefore a higher equity return would be justified. AG Ex. 4.0 at 31, citing NSG Ex. 3.0 at 13 and PGL Ex. 3.0 at 13.

Despite these risks, Integrys recently told investors that the company could increase its consolidated earnings in the range of 4% to 6% *per* year on an average annualized basis "for the foreseeable future." AG Ex. 4.0 at 31. Increases in the price of propane and supply shortages have accelerated natural gas conversions through the respective utility service territories. *Id.* In the Fourth Quarter 2013 Earnings conference call, one Integrys executive reported that "fourth quarter and full year 2013 consolidated financial results were at the higher end of expectations we set in our third quarter earnings conference call last November and were significantly better than our financial results for the same periods in 2012. Our utilities performed well and continue to be the core of our earnings." AG Ex. 4.0 at 32. Integrys good performance was reported to be "based solely on our strong utility growth" as "regulated businesses are our core…and provide the vast majority of our earning and our growth." AG Ex. 4.0 at 32.

Colton's examination of Integrys' own assessment of its utility companies' financial performance leads him to conclude that there has been no attempt to balance ratepayer interests against the optimistic projections of growth and prosperity offered for North Shore and Peoples. AG Ex. 4.0 at 33. If the Companies have failed to balance their need for a fifth rate increase in six years against the needs of their struggling ratepayers, then the Commission must perform that balancing itself.

Commission Analysis and Conclusion

Upon a thorough review of the record, the Commission finds that the appropriate revenue requirement for North Shore is $86,955,000. The Commission is cognizant of the need to balance the interests of rate payers entitled to fair and reasonable rates with the financial requirements of the Companies. The Commission concludes that the adjustments to the revenue requirement reflected in this Order are supported by the evidence.

B. Peoples Gas

Companies' Position

Peoples Gas' final proposed base rate revenue requirement (as revised in its rebuttal testimony and slightly reduced in its surrebuttal testimony) is $680,801,000, or $697,407,000 if costs recovered as Other Revenues ($16,606,000) are included, and Peoples Gas states that its revenue requirement is just and reasonable based on the testimony and other exhibits in evidence. *E.g.*, NS-PGL Ex. 36.0 at 3; NS-PGL Ex. 36.1P, lines 1, 4, 9, and 10, col. [G].

At each of the direct and rebuttal testimony stages, Peoples Gas presented pie charts and additional information showing the drivers of the net changes in their distribution costs of service and revenues forecasted for 2015 versus the levels expected in 2015 under the rates approved in the Utilities' 2012 rate cases. The Peoples Gas rebuttal information was not significantly changed by the surrebuttal revenue requirement reduction. NS-PGL IB at 12.

Staff's Position

Staff recommends a revenue requirement of $667,945,000 as reflected on page 1 of Appendix B to Staff's Initial Brief. Staff recommends an increase to base rates of $69,405,000 and an increase of $1,674,000 to other revenues for a total increase of $71,079,000 (11.91%). Staff's overall recommended increase is $29,462,000 less than the $100,541,000 increase requested by Peoples Gas in surrebuttal.

AG's Position

Notwithstanding their objection to the uncertainty of the 2015 test year as described in part III.C below, the AG recommends reducing the proposed revenue requirement (see NS-PGL Ex. 36.0 at 3:56) of Peoples Gas by $56.728 million, as shown at AG Exhibit 7.2, page 1 (Schedule DJE PGL A) at the bottom of the "AG Proposed Adjustments" column. This proposed adjustment is not meant to oppose (or support) any adjustment proposals offered by other parties in this proceeding that the AG has not commented on.

Commission Analysis and Conclusion

The Commission finds that the appropriate revenue requirement for Peoples Gas is $671,631,000. As the Commission acknowledged in the preceding section of this Order, it is very cognizant of the need to balance the interests of ratepayers entitled to fair and reasonable rates with the financial requirements of the Companies. The Commission concludes that the adjustments to the revenue requirement reflected in this Order are supported by the evidence.

C. Proposed Reorganization

Companies' Position

The Utilities note that the proposed acquisition by Wisconsin Energy Corporation ("WEC") of the ultimate parent company of the Utilities, Integrys, is pending before the Commission in Docket No. 14-0496. That is the proper forum for any proposals relating to whether, or on what terms, the reorganization should be approved. 220 ILCS 5/7 204. NS-PGL IB at 13.

The Utilities and Staff agree that no adjustment to the Utilities' revenue requirements is warranted by the reorganization, provided that Staff proposes one very minor change to one amortization period, as discussed in Section V.C.4 of this Order. The Utilities emphasize that there is no proposal by Staff or any intervenor, nor any basis in the evidence in the record, for any revenue requirement adjustments or other changes to the Utilities' proposals in the instant cases based on the proposed reorganization, and Staff agrees, with that minor exception. The Utilities add that the AG is trying to use the proposed reorganization as secondary support for some of its proposed adjustments, and that CCI, which presented no evidence on this subject, for the first time in its Initial Brief, made proposals relating to the proposed reorganization, but those proposals relate to the reorganization as such and are not proposed adjustments to the Utilities' revenue requirements. NS-PGL IB at 15-16; NS PGL RB at 13-16.

AG witness David Effron noted the June 23, 2014 announcement of the proposed WEC Integrys transaction, which referred in part to anticipated "operational and financial benefits". AG Ex. 1.0 at 4-5. Mr. Effron did not point to anything in the merger announcement (or any other information) that identified any specific potential benefits that would or might result in net savings by the Utilities in relation to their distribution costs of service in 2015 (or at any specific time). In fact, he went on to state in part: "It is unclear the extent to which the Companies' costs of service will be affected by the 'operational and financial benefits' referenced in the merger announcement or the extent to which these benefits should be incorporated into the determination of the Companies revenue requirements and rates. The Companies should describe and quantify the expected operational and financial benefits of the proposed merger in their Rebuttal testimony and should explain why it would or would not be appropriate to incorporate those expected operational and financial benefits into the determination of their test year revenue requirements." *Id.* at 5.

Again, while no adjustments have been proposed based on the proposed transaction, the Utilities state that the evidence would not support any adjustment, in any event. In rebuttal testimony, the Utilities stated in part:

> The proposed transaction is the acquisition of the ultimate parent company of the Utilities, Integrys Energy Group, Inc., by Wisconsin Energy Corporation ("WEC"). The Utilities are not being directly acquired by WEC. The proposed transaction is subject to approval by the Commission and several other state and federal governmental entities. Whether all of the required approvals will be received is unknown. With respect to Illinois, the application for approval that must be filed with the Commission under Section 7-204 of the Public Utilities Act has not yet been filed. In addition, it is possible that future regulatory approvals, if obtained, will be subject to conditions. Thus, whether the transaction will close, whether it will be subject to conditions, the substance of the

> conditions, if any, and when the transaction will close are unknown.

NS-PGL Ex. 17.0 at 10.

The Utilities point out that Staff agrees that no revenue requirement adjustments should be made based on the proposed reorganization (subject to the minor amortization item noted earlier). In rebuttal testimony, Staff discussed materials that were filed in Docket No. 14-0496 as well as data request responses of the Utilities in the instant cases relating to the proposed reorganization. Staff Ex. 6.0 at 23-25 and Attachment B. Staff witness Dianna Hathhorn concluded, based on her analysis, as follows:

> Q. Is it reasonable that the Companies' 2015 test years do not reflect future costs savings for the Reorganization?
>
> A. Yes, in light of the fact that the Reorganization is not guaranteed and even if it is approved, the conditions and timing of its approval cannot be known, it is reasonable that future cost savings are not reflected in this rate proceeding. In addition, based on the information provided by the Companies as to their current expectations with respect to the Reorganization, it is also reasonable that the Companies' 2015 test years do not reflect future cost savings from the Reorganization due to the expected timing of the closing of the Reorganization and Integrys' expectation of savings and shareholder benefits to earnings occurring outside of the test year.

Id. at 24- 25.

The Utilities note that Ms. Hathhorn added that, under some circumstances, if savings were realized sooner than expected, it is her understanding that the Commission could investigate and enter a temporary order fixing a temporary schedule of rates (under 220 ILCS 5/9 202), and that the Commission could condition its approval of the reorganization on a sharing of savings or other conditions (under 220 ILCS 5/7 204). Staff Ex. 6.0 at 25. The Utilities argue that those legal points are not pending and need not be briefed here, but, without discussing specifics of the scope of the Commission's authority and the procedures through which and grounds upon which it may act, it is correct that the Act contains provisions regarding interim rate orders (220 ILCS 5/9 202) and conditions upon approvals of a reorganization (220 ILCS 5/7 204). NS-PGL IB at 15; NS-PGL RB at 17-18.

The Utilities note that Staff also has pointed out that the Utilities are not proposing to include in their costs of service in these cases the acquisition premium or costs incurred to approve the reorganization, even though such costs would be incurred in 2015, the test year, if the reorganization is approved. Staff IB at 5. In addition, the Utilities note that Staff explained that the Act contains not only provisions for conditions upon approvals of a reorganization (220 ILCS 5/7 204), but also provisions regarding interim rate orders (220 ILCS 5/9 202) and requests for investigations of rates (220 ILCS 5/9 250), which could address the hypothetical situation of net costs savings occurring after the reorganization closes. Staff IB at 4 7.

The Utilities point out that AG witness Mr. Effron, in his rebuttal, speculated that the proposed reorganization might lead to cost savings, but that he neither proposed, nor presented facts supporting, any adjustment to the Utilities' revenue requirements based on the proposed reorganization, except that, in relation to his proposed adjustments to Integrys Customer Experience ("ICE") project costs, he speculated that the proposed reorganization, if approved, might lead to cancellation of the ICE project. *See* AG Ex. 7.0 at 22-25; NS-PGL IB at 7; NS-PGL RB at 14. In addition, the Utilities note that Mr. Effron offered conjecture that the proposed reorganization might lead to lower overall costs, and that the AG in briefing added the argument that the reorganization might also indirectly support his proposed adjustments to the Utilities' employee levels. The Utilities argue that the AG's speculation lacks any valid factual basis, and that any such issues belong in the other Docket.

The Utilities state that their witness Mr. Derricks in his surrebuttal: (1) discussed Ms. Hathhorn's rebuttal testimony, largely agreeing with it; (2) pointed out that Mr. Effron's rebuttal testimony's speculation is speculation, as also shown by several data request responses of Mr. Effron; (3) pointed out that Mr. Effron's rebuttal's speculation does not make sense given the timeline of the proposed reorganization and other facts, *e.g.*, that the transaction, if approved, is not expected to close until Summer 2015; and, moreover, (4) noted that speculation about hypothetical future cost reductions that might offset the needed rate increases is unwarranted, because the reality is that Peoples Gas is experiencing a significant increase in paving costs that is not reflected in its proposed revenue requirement. NS-PGL Ex. 33.0 at 5-8; NS-PGL Ex. 33.1. *See also* NS-PGL Cross Ex. 3 (additional data request responses of Mr. Effron); NS-PGL Ex. 38.0 at 8; NS-PGL Ex. 38.2 (regarding Peoples Gas' paving costs, showing they are almost $8 million over the forecast for the first eight months of 2014).

The Utilities state that, for example, Mr. Effron admitted that he did not review any information from past transactions regarding the amount of time that elapses between when a transaction closes and when a net decrease in expenses, if any, first occurred. NS-PGL Ex. 33.0, 6:129 – 7:149 (citing and quoting data request responses of Mr. Effron).

The Utilities state that Mr. Effron's failure to examine when net savings occur after a transaction (if they do) is even more problematic than the above may suggest, because he also did not take into account Staff's point that the Utilities are not proposing to include in their costs of service in these cases the acquisition premium or other costs to be incurred to approve the reorganization, even though such costs would be incurred in 2015, the test year, if the reorganization is approved. Staff IB at 5. Such costs, if considered and applied here, would increase, not decrease, the Utilities' test year costs. The Utilities are not proposing to include any such costs, which would not be appropriate in the current cases, but they do note that it is well established that costs incurred to achieve savings may be recovered through rates. NS-PGL IB at 15, fn. 12.

Thus, the Utilities summarize that Mr. Effron speculated about net savings, while not analyzing any information regarding when they might occur, and while ignoring the costs that will be incurred to achieve those savings, which costs would include significant costs in 2015.

The Utilities contend that speculation is not a lawful basis for a Commission decision. *See, e.g., Ameropan Oil Corp. v. ICC,* 298 Ill. App. 3d 341, 348, 698 N.E.2d 582, 587 (1st Dist. 1998) ("speculation has no place in the ICC's decision"); *Allied Delivery System. Inc. v. Illinois Commerce Comm'n,* 93 Ill. App. 3d 656, 667, 417 N.E.2d 777, 785 (1st Dist. 1981) ("The speculation indulged in by the Commission is clearly an unsatisfactory and unacceptable basis for its decision.")

The Utilities also contend that the AG's position is inconsistent. The AG has previously, and successfully, opposed the Utilities' use of an end of year rate base in future test year rate cases, rejecting the Utilities' argument that an end of year rate base would better reflect higher levels of investment as the rates being set remain in effect after the test year, on the grounds that other cost factors may increase or decrease after the test year. *See, e.g., North Shore Gas Co./The Peoples Gas Light and Coke Co.*, Docket Nos. 12-0511/12-0512 (Consol.), Order at 26 (June 18, 2013). However, the Utilities note that in the instant proceeding, the AG conjectures about post-reorganization net cost savings that may or may not occur, and that would not be expected to occur in 2015, while ignoring all other factors influencing the Utilities' costs of service, such as the costs of the reorganization itself, costs to achieve savings, and increased paving costs, the third of which is an already occurring known fact that is not reflected in Peoples Gas' revenue requirement. NS-PGL RB at 15-16.

The Utilities note that CCI presented no evidence on this subject and yet, CCI, in its Initial Brief (at 5), claimed that the Commission lacks sufficient information about whether the rates set in the current cases will remain appropriate under the changed conditions that may prevail after the reorganization closes in summer 2015, assuming approval of the reorganization. CCI does not oppose use of the 2015 test year. *Id.* However, CCI now proposes that the Commission in the current cases, not in the reorganization docket, impose a list of cost and revenue tracking, reporting, and filing requirements and even dividend limitations. *Id.* at 6-7.

The Utilities contend that CCI's proposals have no factual basis in the evidence, and to adopt them would be unlawful, for multiple reasons. To begin with, CCI purports to support its proposal to impose reorganization related requirements in the instant cases, rather than in the reorganization approval Docket, based on arguments that have no basis in fact or law. NS-PGL RB at 16.

The Utilities contend that those assertions come out of left field and are baseless and incorrect. 220 ILCS 5/7 204 is exactly the provision of the Act that governs the conditions that may be imposed upon approval of the proposed reorganization, and ICC Docket No. 14 0496 is the sole Docket in which the Commission is considering and can and must consider such issues. 220 ILCS 5/7 204 does not permit such issues to be litigated in multiple dockets, and to do so would cause duplicative litigation and could result in inconsistent outcomes. Moreover, Staff witness Ms. Hathhorn did not contend that any reorganization related requirements could or should be imposed in the instant cases. The opposite is true. Furthermore, CCI points to no deficiency in 220 ILCS 5/9-202 and 220 ILCS 5/9-250, which Staff has cited, and in fact CCI itself cites. CCI IB at 7.

CCI's assertion that the record in Docket No. 14-0496 "is not certain to contain sufficient evidence" has no foundation. Discovery is occurring in that Docket, as has been referenced here. *See, e.g.*, AG Cross Ex. 11. Moreover, Staff and intervenor testimony in that Docket is not even due until November 20, 2014 (and, on certain issues, not until November 26, 2014). CCI does not even attempt to claim that, much less explain why, it could not make the same proposals in the reorganization Docket. There is no factual or legal basis for imposing any reorganization related requirements in the instant cases. NS-PGL RB at 16-17.

The Utilities further contend that, in addition, and perhaps even more importantly, CCI's specific list of proposed requirements itself lacks any basis in the evidence. CCI did not make any of those proposals until CCI's Initial Brief. No other party made any such proposals. No witness supported CCI's proposals, and no witness had the chance to oppose them. There was no discovery or cross examination regarding CCI's proposals. NS-PGL RB at 17.

The Utilities contend that, thus, to approve CCI's list of proposals in the instant cases: (1) not only would contravene 220 ILCS 5/7-204; but (2) it would be contrary to the Commission's basic duty to decide these cases based on the evidence in the record and the applicable law, 220 ILCS 5/10-103; 220 ILCS 5/10-201(e)(iv)(A); and (3) it also would be contrary to due process, due to the lack of affording the Utilities notice and a fair opportunity to be heard regarding CCI's proposals, *See, e.g., Quantum Pipeline Co. v. Illinois Commerce Comm'n,* 204 Ill. App. 3d 310, 709 N.E.2d 950 (3d Dist. 1999). The due process violation would be even worse than the above discussion indicates, because it is not only the Utilities' rights that would be violated. Wisconsin Energy Corporation and four of the six other applicants in Docket No. 14-0496 are not parties to the instant cases. Their due process rights will be violated if requirements are imposed here based on the proposed reorganization. Moreover, other parties might intervene in that Docket that are not parties here, and, if so, their due process rights will be violated as well. NS-PGL RB at 17-18.

Finally, the Utilities contend that CCI's proposals lack merit even on their face. Several of the proposals involve cost and revenue and other information tracking and reporting, but CCI does not discuss any of the Utilities' existing obligations, such as their duty to file an annual ICC Form 21, and, again, CCI does not explain why the reorganization Docket could not handle any valid concerns on this subject. CCI goes even farther, urging the Commission to order the Utilities to file new rate cases by a date certain or defined in relation to the reorganization. Here, too, CCI does not explain why any concerns could not be handled in the reorganization Docket and/or under Sections 9-202 and 9-250. Moreover, the Utilities have a legal right to determine when they will file rate cases, *Lowden v. Illinois Commerce Comm'n*, 376 Ill. 225, 231, 33 N.E.2d 430, 434 (1941), so it is only under Section 7-204 in the reorganization Docket, as a possible condition of approval, that the Commission could address such a proposal, although, again, the Commission also would have Sections 9-202 and 9-250 available as measures to investigate and change rates. CCI goes still farther, by urging the Commission to limit post-reorganization dividends, which is a breathtakingly irresponsible proposal with no factual or legal basis, and which would be an additional due process violation in its own right by directly affecting the rights of investors with no notice or opportunity to be heard. CCI's proposals must be rejected.

The test year in this case is 2015. The Utilities contend that there is nothing in the record that supports any suggestion that the proposed reorganization might lead to net savings in 2015. The evidence is to the contrary. Moreover, any such issue belongs in the reorganization Docket.

The Utilities argue that the proposed reorganization, in terms of approval and possible conditions, is not a part of the instant cases, is not a basis for any adjustment in the instant cases, and must and will be addressed in Docket No. 14 0496, not here. The AG's conjectures and CCI's proposals must be rejected. NS-PGL IB at 13; NS-PGL RB at 19.

Staff's Position

Section 9-201(c) of the PUA provides in part that "[i]f the Commission enters upon a hearing concerning the propriety of any proposed rate or other charge, classification, contract, practice, rule or regulation, the Commission shall establish the rates or other charges, classifications, contracts, practices, rules or regulations proposed, in whole or in part, or others in lieu thereof, which it shall find to be just and reasonable." 220 ILCS 5/9-201(c). Based on the circumstances of the proposed merger and this proceeding's record described below, it is reasonable that (i) the Companies did not provide any information in this docket about future cost savings regarding the proposed merger and possible acquisition of the ultimate parent company of the Companies, Integrys by WEC ("Reorganization"); and (ii) the Companies' proposed rates, which are based upon 2015 test years, do not reflect future costs savings of the Reorganization. Staff Ex. 6.0 at 24-25. In Staff's view, because the Reorganization is not guaranteed, and even if it is approved, the conditions and timing of its approval cannot be known; it is reasonable that future cost savings are not reflected in this rate proceeding.

The AG recommended that the Companies describe and quantify the expected operational and financial benefits of the Reorganization. AG Ex. 1.0 at 4-5. Companies' witness Derricks responded generally that the Reorganization is subject to future regulatory approvals, and the conditions and timing are unknown. NS-PGL Ex. 17.0 at 10. Since the filing of the Companies' rebuttal testimony, the Companies filed their Application for the Reorganization in Docket No. 14-0496. The Companies' responses to discovery concerning the Reorganization's effect on the 2015 test year revenue requirement are included in Attachment B to Staff Ex. 6.0.

Staff witness Hathhorn testified concerning the timing of the pending rate cases with the Reorganization and whether it was reasonable that the Companies' proposed rates do not reflect future costs savings from the Reorganization. Staff Ex. 6.0 at 24. In the Fact Sheet filed in Docket No. 14-0496, as part of the filing requirements under Section 7-204A(a)(2)(ii) (Staff Ex. 6.0, Attachment B), Integrys states that the expected closing of the transaction is summer 2015. The Companies are not requesting cost recovery of the acquisition premium, *i.e.*, the price above book value, or the costs incurred to accomplish the Reorganization (Docket No. 14-0496, Petition at 13), although these costs are expected to be incurred within the 2015 test year. The Reorganization is expected to have potential long-term synergy savings. (Attachment B.) The Fact Sheet states further that the combination is accretive to earnings *per* share in the first full calendar year after closing, likely 2016 based on the expected closing date.

In light of the fact that the Reorganization is not guaranteed, and even if it is approved, the conditions and timing of its approval cannot be known, it is reasonable that future cost savings are not reflected in this rate proceeding. In addition, based on the information provided by the Companies as to their current expectations with respect to the Reorganization, it is also reasonable that the Companies' 2015 test years do not reflect future cost savings from the Reorganization due to the expected timing of the closing of the Reorganization and Integrys' expectation of savings and shareholder benefits to earnings occurring outside of the test year. Staff Ex. 6.0 at 24. Under some circumstances, however, if the Reorganization is approved and savings are realized sooner than expected, the rates derived from this proceeding may need to be adjusted. 220 ILCS 5/9-250. Further, should information become known that would materially change these expectations, the Commission has the authority to investigate the Companies' rates and/or enter a temporary order fixing a temporary schedule of rates under Article 9 and to condition its approval of the Reorganization on the appropriate sharing of savings or to require compliance with other conditions to reflect the Reorganization's impact on rates. 220 ILCS 5/9-202.

Finally, based on the information provided by the Companies in this proceeding, Staff's finance expert witness, Janis Freetly, testified that there is no need to adjust Staff's recommended rate of return on rate base due to WEC's proposed acquisition of Integrys. At this time, it is unknown if the reorganization will occur and if so, how the reorganization will affect the Companies' rate of return. Staff Ex. 8.0 at 21. Should information become known that would materially change the rate of return on rate base, however, the Commission has the authority to investigate the Companies' rates under Article 9 as discussed above, and to condition its approval of the reorganization on a revised rate of return on rate base should the merger impact that set in this proceeding pursuant to Section 5/7-204(f) of the PUA. *Id.*

<u>AG's Position</u>

As AG witness David Effron noted in direct testimony, the recently (June 23, 2014) announced acquisition agreement between Integrys – the parent of North Shore and Peoples Gas – by Wisconsin Energy Corp makes reference to "operational and financial benefits" that are "clear, achievable and compelling" and states that the transaction will be "accretive to Wisconsin Energy's earnings *per* share in the first full calendar year after closing." AG Ex. 1.0 at 4-5. The anticipated closing for the merger is the summer of 2015, which is the middle of the future test year in this proceeding. The extent to which the Companies' costs of service will be affected by the "operational and financial benefits" referenced in the merger announcement, or the extent to which these benefits should be incorporated into the determination of the Companies' 2015 revenue requirement in this proceeding, is completely unclear. *Id.* at 5. The lack of clarity around North Shore's and People's future should raise the question of whether the notion of deciding a 2015 revenue requirement in this proceeding is even coherent.

Mr. Effron advised in direct testimony that "[t]he Companies should describe and quantify the expected operational and financial benefits of the proposed merger in their Rebuttal testimony and should explain why it would or would not be appropriate to incorporate those expected operational and financial benefits into the determination of their test-year revenue requirements." *Id.* at 5. Rather than complying with Mr. Effron's suggestion, the Companies only cited uncertainties regarding the scheduled July 2015 closing of the proposed transaction in their rebuttal testimony and in discovery responses. *See, e.g.*, NS-PGL Ex. 17.0, at 10 ("[t]he proposed transaction is subject to approval by the Commission and several other state and federal governmental entities. Whether all of the required approvals will be received is unknown. In addition, it is possible that future regulatory approvals, if obtained, will be subject to conditions"); *see also* Staff Ex. 6.0, Attachment B, PGL response to Staff data request DGK 30.01 ("there are too many uncertainties for the Utilities to have an expectation regarding this subject"). In light of the numerous uncertainties around the pending merger, it is thus difficult to understand how the Commission can set a test-year revenue requirement based on 2015 expenses. Mr. Effron advised in rebuttal testimony that:

> [g]iven that mergers and acquisitions frequently result in decreases to expenses, the expense increases being forecasted by the Companies seem especially speculative in the circumstances, as the merger should enable the Companies to, at a minimum, avoid such increases. . . . The merger is forecasted to close in the summer of 2015. The inability or unwillingness of the Companies to quantify the operational and financial benefits calls into question the reliability of the forecasted costs for 2015, the test year in this case and the first year that the rates established in this case will be in effect. It is entirely possible that the merger will generate cost savings well beyond the mitigation of the expense increases that I have addressed. In effect, the Companies are asking the Commission to base rates on costs that may not comport with the post-merger reality. Given the uncertain effects of the merger, the Commission should question whether any rate changes are appropriate at this time.

AG Ex. 7.0 at 24-25. The AG echoes Mr. Effron's suggestions in urging the Commission to consider whether there should be any rate changes at this time of great uncertainty for 2015.

<u>CCI's Position</u>

The Companies have asked the Commission to approve proposed rate increases based on a 2015 Test Year. The 2015 Test Year is presented as representative of the period the rates determined in this case will be in effect. *See*, *e.g.*, PGL Ex. 5.0 at 2. The rates set in this proceeding will remain in effect until NS-PGL elects to file another rate case, or until the Commission orders an examination of NS-PGL's rates for other reasons. Currently, the Companies are under no obligation to resubmit their comprehensive costs and revenues for regulatory scrutiny within a definite period.2 In the past, the Companies' rates have remained unreviewed in a rate proceeding for as long as a dozen years (between Dockett No. 95-0032 and Docket Nos. 07-0241/02422 (Consol.).

At the same time, the Companies are also applicants seeking Commission approval of the acquisition of NS-PGL's parent company (and indirectly of the Companies) by a Wisconsin utility holding company. NS-PGL Ex. 17.0 at 10. If approved, the proposed reorganization would close in the middle of the 2015 Test Year being used in this case to set rates. NS-PGL Ex. 33.0 at 7. The effects of the reorganization (if approved) on the Companies' costs of service are unknown. Indeed, the potential changes to NS-PGL's costs of service are not addressed in this proceeding. The Companies avow a near-total lack of knowledge about potential changes in the Companies' costs of service. They suggest that it is possible that future regulatory approvals, if obtained, will be subject to conditions. NS-PGL Ex. 33.0 at 3. "[W]hether the transaction will close, whether it will be subject to conditions, the substance of the conditions, if any, and when the transaction will close are unknown." *Id.*

There can be no doubt the transaction, if it closes in 2015, will have some effect on the Companies' costs during the 2015 test year and going forward, effects that are not considered in this rate proceeding. Predictably, intervenors in this case (non-parties to the proposed reorganization transactions) have even less access to information about plans for, and the costs of, integrating affected entities, systems, and operations.

As a result, the Commission lacks adequate information to reach an informed conclusion about whether rates determined on a (pre-reorganization) 2015 Test Year will be appropriate under the changed conditions that a reorganization would engender. The proposed reorganization may cause significant (but currently unquantified) changes in the Companies' costs of service -- in the Test Year and beyond. *See* AG Ex. 7.0 at 475-481. It is not certain that the rates approved in this proceeding will remain just and reasonable under the changed circumstances of a reorganization. See Staff Ex. 6.0 at 25 ("Staff is aware of the fact that under some circumstances, if the Reorganization is approved and savings are realized sooner than expected, the rates derived from this proceeding may need to be adjusted.")

Notwithstanding these concerns, CCI do not oppose use of the 2015 test year. However, that lack of opposition exists only because (a) no superior basis for future rates is currently available and (b) CCI expect that the Commission will use its regulatory authority to appropriately qualify its 2015 Test Year rate determinations. The 2015 Test Year in this case reflects circumstances the Companies are working actively to alter dramatically, during the Test Year. The focus of the reorganization proceeding, moreover, is structural realignment, not ratemaking, and it cannot reasonably be expected to provide a quantitative basis for tariff rate decisions. Accordingly, the Commission must act to assure timely re-examination of the Companies' rates, in the new circumstances of a reorganization the Commission may approve almost immediately after rates are fixed using pre-reorganization cost data. The Commission's Staff expert has recognized the potential for harm to ratepayers.

Coordinating Commission orders in this rate case and in the pending reorganization proceeding will be a challenge for the Commission. However, the risks or burdens of that challenge should not fall on the Companies' customers, who did not initiate either the proposed rate changes or the proposed reorganization.

To enable timely investigation of the appropriateness of the Companies' rates under the changed conditions of a reorganization, the Commission should order an appropriate combination of the following prudent actions to protect ratepayers:

- order the Companies to report any significant change in their costs of providing regulated services, and any significant change in amounts allocated to the Companies from other affiliates, so the Commission can assess the appropriateness of possible orders to show cause why NS-PGL rates should not be reduced;

- order the Companies to separately track and record all costs, whether expenses or investments, associated with the reorganization (including costs attributable to transitions to common accounting, computer, and other management systems, to mergers of organization structures, and consolidation of operations), so that the Commission can assure that costs unrelated to the Companies' provision of regulated services are not included in regulated rates;

- order the Companies to report their actual costs and revenues, with costs attributable to the reorganization excluded and separately stated, with a view to prompt investigation (through show cause proceeding or otherwise -- §§ 9-250; 9-202), if indicated, of whether the Companies' approved rates continue to be just and reasonable;

- order the Companies to file new rates by a date certain (or within a specified period after the reorganization) that reflect (through an appropriate test year) the changed conditions occasioned by the reorganization;

- order the Companies (a) to limit any post-reorganization dividend pay-outs from the Companies to any affiliates to a level representative of pre-reorganization pay-outs and (b) to report any dividend pay-outs to the Commission within 30 days of such pay-outs; and

- order the Companies to report to the Commission, within 14 days of the change, any changes by credit rating agencies to their credit ratings of, or their recommendations concerning, the Companies or any affiliates.

The Commission should not rely solely on conditions or other protective measures that may be ordered in the reorganization proceeding. *See* Staff Ex. 6.0 at 25. The Commission must act in this case, especially because the record in that case is not certain to contain sufficient evidence on ratemaking issues to support directives that fully protect the Companies' ratepayers.

<u>Commission Analysis and Conclusion</u>

The Commission agrees with Staff that the pending merger case, Docket No. 14-0496, is the more appropriate place to evaluate merger conditions and cost savings arising from the merger. Although the merger is very likely to occur, imposing conditions or requiring concrete savings commitments in another docket in advance of the acquisition is impractical and unwise.

IV. RATE BASE

A. Overview/Summary/Totals

1. North Shore

North Shore's rebuttal testimony presented an average rate base of $219,786,000, reflecting adjustments proposed by Staff and Intervenors that the utility agreed with or accepted in whole or in part and certain updates.

Staff recommends a rate base of $218,599,000 which is $1,187,000 less than the rate base requested by North Shore.

2. Peoples Gas

Peoples Gas' surrebuttal testimony presented an average rate base of $1,759,289,000, reflecting adjustments proposed by Staff and intervenors that the utility agreed with or accepted in whole or in part and certain updates.

Staff recommends a rate base of $1,670,732,000 which is $88,557,000 less than the $1,759,289,000 rate base requested by Peoples Gas in surrebuttal.

B. Potentially Uncontested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Gross Utility Plant

a. 2013 Plant Balances

The Companies' direct cases provided actual plant balances for 2011 and 2012, six months actual data and six months forecasted data for 2013, and forecasts for 2014 and 2015 plant balances. In response, CCI witness Mr. Gorman noted that Peoples Gas' actual distribution plant balance as of December 31, 2013, was less than the forecasted level reflected in the Companies' forecast for December 31, 2013, and recommended that the Companies develop a forecasted rate base reflecting the 2013 actual data. Mr. Gorman did not address North Shore's actual 2013 plant balances, which exceeded its forecasted 2013 balances. In rebuttal testimony, the Companies partially agreed with Mr. Gorman's recommendation, and made an adjustment to each Utility's respective net utility plant balances and Accumulated Deferred Income Taxes ("ADIT") to reflect the actual plant, accumulated depreciation and ADIT for calendar year 2013 as compared to the '6&6' forecast balances. Mr. Gorman did not further address this issue in rebuttal testimony. No witness or party contested the updated 2013 figures. The Commission approves the Companies' updated 2013 plant balances.

b. 2014 Plant Balances (other than PGL AMRP Additions and associated items addressed in Section IV.C.1.a)

The Companies provided forecasts for 2014 plant balances. In response, CCI witness Mr. Gorman and AG witness Mr. Effron presented their respective proposals to adjust the 2014 forecast (in Mr. Effron's case, focusing specifically on Accelerated Main Replacement Program ("AMRP") additions, costs of removal associated with the AMRP additions, and costs of removal associated with other plant additions). In rebuttal testimony, the Companies updated their forecasted 2014 plant balances. Mr. Gorman did not further address this issue in rebuttal testimony. In his rebuttal testimony, Mr. Effron dropped his general costs of removal adjustment, but presented revised adjustments for AMRP costs and the associated costs of removal, as discussed in Section IV.C.1.a. Staff rebuttal witness Ms. Hathhorn proposed to adopt Mr. Effron's direct testimony proposal, subject to it being updated and corrected, although she did not present testimony on the actual merits of the proposal, other than brief speculation. CCI's Initial Brief (at 8) confirmed that it was not proposing any adjustment to 2014 plant balances. Thus, apart from the 2014 AMRP costs and associated costs of removal, the Companies' 2014 plant balances as updated in rebuttal are uncontested (subject to a slight correction of Peoples Gas' figure in surrebuttal that is uncontested, discussed in Section IV.B.1.c.vii, below). The Commission approves the Companies' updated 2014 plant balances, subject to the updates discussed in Section IV.C.1.a of this Order.

c. 2015 Forecasted Capital Additions

(i) In General

The Companies provided forecasts for 2015 plant balances to be included in rate base. The forecasted 2015 plant additions (as revised in rebuttal, where applicable) are uncontested. The Commission approves the Companies' forecasts for 2015 plant balances.

The Companies noted that, pursuant to 83 Ill. Adm. Code § 285.6100, Peoples Gas identified major capital projects added to rate base since Peoples Gas 2012 as a project with a cost greater than the lower of 0.2% of net plant or $10,000,000. Peoples Gas' net plant at December 31, 2012, was $2,131,077,763, and, thus, a major project is one that costs more than $4,262,000. Peoples Gas identified six major capital projects: (1) AMRP, (2) Calumet System Upgrade Project, (3) 2015 casing remediation project, (4) 2014 Gathering System Pipe Replacement project, (5) 2015 Gathering System Pipe Replacement project, and (6) the LNG Control System Upgrade. These projects, discussed below, are uncontested as to 2015.

The Companies further noted that pursuant to 83 Ill. Adm. Code § 285.6100, North Shore identified major capital projects as a project with a cost greater than the higher of 0.2% of net plant or $1,000,000. North Shore's net plant at December 31, 2012, was $263,103,698, and, thus, a major project is one that costs more than $1,000,000. North Shore identified three major capital projects: (1) Wildwood/Gages Lake, (2) Grayslake Gate Station, and (3) Casing Remediation Program. These projects, as discussed below, are uncontested as to 2015.

2014 AMRP costs are discussed in Section IV.C.1.a of this Order. The other major capital projects are discussed below, including both 2014 and 2015 costs.

(ii) Calumet System Upgrade (PGL)

Peoples Gas has reduced its Calumet System Upgrade costs to reflect the updated cost of work that will be completed in 2014, reducing the 2014 expenditures from $43.1 million to $36.3 million. Peoples Gas noted that of this reduced amount, $15.0 million will be in service in 2014 and the remaining $21.3 million will be accounted for as construction work in progress at December 31, 2014. These costs are not contested. The Commission approves the costs associated with Peoples Gas' Calumet System Upgrade project, subject to the updates discussed in Section IV.C.1.a of this Order.

(iii) Casing Remediation (PGL)

Peoples Gas forecasted capital additions in 2014 and 2015 of $10 million for the casing remediation program. These costs are not contested. The Commission approves the costs associated with Peoples Gas' Casing Remediation project.

(iv) Gathering System Pipe Replacement Project (PGL)

Peoples Gas presented two major capital projects for 2014 and 2015: the 2014 Gathering System Pipe Replacement Project and the 2015 Gathering System Pipe Replacement Project. Peoples Gas noted that these projects exceeded the major capital project threshold of $4,262,000. Peoples Gas forecasted capital costs of $5,525,000 for the 2014 Gathering System Pipe Replacement Project, to be expended during calendar year 2014 and capital costs of $6,000,000 for the 2015 Gathering System Pipe Replacement Project, to be expended during calendar year 2015. These costs are uncontested. The Commission approves the costs associated with Peoples Gas' 2014 and 2015 Gathering System Pipe Replacement Project.

(v) LNG Control System Upgrade (PGL)

Peoples Gas forecasted capital additions for its Liquefied Natural Gas ("LNG") Control System Upgrade Project of $8,800,000, to be expended during calendar year 2014. This item was not contested. The Commission approves the costs associated with Peoples Gas' LNG Control System Upgrade Project.

(vi) LNG Truck Loading Facility (PGL)

Companies' Position

Peoples Gas states that it has withdrawn its proposal to develop an LNG Truck Loading Facility to be added to rate base in the 2015 test year. This issue is not contested. However, Staff requests the Commission to rule in this docket that the Companies should, prior to developing any potential LNG Truck Loading Facility or entering into any contracts related to the sale of LNG from such a facility, make a filing seeking approval under 220 ILCS 5/7-102. The Companies argue that such a ruling would be premature, as there is no LNG Truck Loading Facility proposed for consideration in front of the Commission. The Companies also maintain that there is insufficient evidence in this docket to make such a determination.

Staff's Position

Staff notes that in rebuttal, Peoples Gas witness Thomas Puracchio stated Peoples Gas reserves the right to construct and operate a LNG Truck Loading Facility and to seek recovery through rates in the future. Staff reiterated its recommendation that Peoples Gas receive Commission approval pursuant to Article 7 of the Act to construct and operate the LNG Truck Loading Facility in Staff Witness Mr. Seagle's rebuttal testimony. In surrebuttal, Mr. Puracchio stated the issue of what activities require Commission approval are a legal matter that Peoples Gas will address in briefs rather than in testimony.

Staff argues that Section 7-102 (A)(g) states:

> Unless the consent and approval of the Commission is first obtained or unless such approval is waived by the Commission or is exempted in accordance with the provisions of this Section or of any other Section of this Act:
>
> (g) No public utility may use, appropriate, or divert any of its moneys, property or other resources in or to any business or enterprise which is not, prior to such use, appropriation or diversion essentially and directly connected with or a proper and necessary department or division of the business of such public utility; provided that this subsection shall not be construed as modifying subsections (a) through (e) of this Section.

220 ILCS 5/7-102(A)(g). Staff argues that Section 7-102(A)(g) requires that, among other things, Companies only use their property in a manner which is directly related to the business of providing utility services. The purpose of these provisions of the Act is to assure both that ratepayers are adequately served by the utility and that the utility receives reasonable return for its services. *Village of Hillside v. Ill. Commerce Comm'n*, 111 Ill.App.3d 25 (1st Dist. 1982).

Staff argues that despite Peoples Gas' willingness to withdraw its request for cost recovery, the Commission should require Peoples Gas to seek approval pursuant to Section 7-102 of the PUA (220 ILCS 5/7-102) prior to initiating the construction of a LNG Truck Loading Facility or entering into contracts to sell LNG by means of the LNG Truck Loading Facility at its Manlove Underground Gas Storage Field.

Commission Analysis and Conclusion

Staff witness Seagle recommended the Commission reduce Peoples Gas' rate base, regarding a LNG Truck Loading Facility, by $4,000,000. In rebuttal, Peoples Gas withdrew its proposal to develop an LNG Truck Loading Facility to be added to rate base in the 2015 test year. This issue is not contested. Requiring Peoples Gas to seek approval pursuant to Section 7-102 of the Act prior to initiating the construction of a LNG Truck Loading Facility or entering into contracts to sell LNG by means of the LNG Truck Loading Facility is premature.

(vii) Reclassification of Costs to Plant in Service (PGL)

Peoples Gas noted that an adjustment to reclassify certain costs from operations and maintenance ("O&M") expenses to Plant in Service was inadvertently omitted from Peoples Gas' rebuttal revenue requirement, and updated its adjustment accordingly to reflect the reduction to O&M expense offset by derivative depreciation expense and income taxes on Plant in Service. This adjustment is uncontested. The Commission approves Peoples Gas' coordinated adjustment to rate base and O&M expenses.

(viii) Wildwood/Gages Lake (NS)

North Shore forecasted capital additions for its Wildwood/Gages Lake project of $2,400,000 for 2014 and 2015. These costs were not contested. The Commission approves the costs associated with North Shore's Wildwood/Gages Lake project.

(ix) Grayslake Gate Station (NS)

North Shore forecasted capital additions for its Grayslake Gate Station project of $6,525,000 for 2014 and 2015. These costs were not contested. The Commission approves the costs associated with North Shore's Grayslake Gate Station project.

(x) Casing Remediation (NS)

North Shore forecasted capital additions for its Casing Remediation project of $6,250,000 for 2014 and 2015. These costs were not contested. The Commission approves the costs associated with North Shore's Casing Remediation project.

(xi) Locker Room (NS)

North Shore withdrew the Locker Room project from this rate case. The calculation of the resulting plant reductions as presented in North Shore's rebuttal testimony is uncontested. The Commission approves North Shore's plant reductions for this project.

d. Original Cost Determinations as to Plant Balances as of December 31, 2012

The Companies and Staff agree to the original cost determinations of $443,539,000 for North Shore and $3,285,370,000 for Peoples Gas as of December 31, 2012. They agreed that the following language should be included in the Findings and Ordering Paragraphs of the Commission's final Order. That language is:

> It is further ordered that the $443,539,000 original cost of plant for North Shore at December 31, 2012 and the $3,285,370,000 original cost of plant for Peoples Gas at December 31, 2012, as presented in Staff Exhibit 1.0, are unconditionally approved as the original costs of plant.

The Commission approves that language, which appears in the Findings and Ordering Paragraphs, below.

2. Accumulated Provisions for Depreciation and Amortization (including new depreciation rates and including derivative impacts other than in Section IV.C.1.a)

The inclusion of Plant in Service in rate base is subject to reduction for the associated applicable Accumulated Provisions for Depreciation and Amortization. The balances for accumulated depreciation and amortization, subject to derivative impacts, if any, as presented by the Companies, are $200,691,000 for North Shore and

$1,245,048,000 for Peoples Gas, based on actual per book data and projected data as applicable. This subject is uncontested, apart from derivative impacts, if any, of the items discussed in Section IV.C.1.a below. The Commission approves the balances for accumulated depreciation and amortization, subject to derivative impacts.

The Companies note that the depreciation rates used in these cases are new rates based on a study supported by independent expert Companies witness John Spanos. The Companies explain that this reflects the Commission's past direction that the Companies prepare a new study every five years. The new rates are uncontested. The Commission approves the new depreciation rates provided by the Companies.

3. Cash Working Capital (other than Section IV.C.2)

The Companies explain that cash working capital ("CWC") is the amount of funds required to finance the day-to-day operations of a utility. The Companies note that CWC usually is calculated using a "lead/lag study", which is a study of the applicable cash flows, and that is how it has been calculated in the instant cases. The Companies note that the CWC figure is independently calculated for the test year, so it is not an average.

The final CWC calculations presented by the Companies based on their lead/lag studies as updated in rebuttal (North Shore) and surrebuttal (Peoples Gas) are $(1,721,000) for North Shore and $10,783,000 for Peoples Gas. The Companies and Staff agree on the calculation of CWC, subject to the item in the next paragraph of this Order, and agree that the final balances of CWC will be established using the applicable final inputs ultimately approved in this proceeding.

This subject is uncontested with the exception of the "expense lead" for other post employment benefits ("OPEB") expenses, discussed in Section IV.C.2.a below, and derivative impacts on the inputs to the CWC calculation, if any, of contested operating expense adjustments. Therefore, the Commission approves the final CWC calculations presented by the Companies, subject to the determination of the OPEB expense lead issue and the derivative impacts, if any, of rulings on contested issues that affect the final inputs to the CWC calculations.

4. Materials and Supplies, Net of Accounts Payable

Consistent with the Commission's Orders in the Companies' recent rate cases, the Companies presented the 13-month average balances of materials and supplies, net of accounts payable, based on actual per book data and projected data as applicable. The 13-month averages (net) for test year 2015 are $1,928,000 for North Shore and $15,302,000 for Peoples Gas. This subject is uncontested. The Commission approves the Companies' 13-month average balances of Materials and Supplies, net of accounts payable.

5. Gas in Storage

Consistent with the Commission's Orders in the Companies' recent rate cases, the Companies presented the 13-month average balances of Gas in Storage based on actual per book data and projected data as applicable. The 13-month averages for test year 2015 are $6,238,000 for North Shore and $47,405,000 for Peoples Gas. This subject is uncontested. The Commission approves the Companies' 13-month average balances of Gas in Storage.

6. Budget Plan Balances

The Companies note that Budget Plan Balances may be a component (reduction) of rate base when they provide a source of capital. The Companies presented the 13-month average balances of Budget Plan Balances based on actual per book data and projected data as applicable. The 13-month averages for test year 2015 are $831,000 for North Shore and $10,847,000 for Peoples Gas. In addition, the Companies accepted Staff's recommended adjustment to reflect the use of the Commission's ordered interest rate of 0% to be paid on customer deposits as the rate at which budget payment plan balances will accrue interest. This subject is uncontested. The Commission approves the Companies' Budget Plan Balances and the use of the interest rate of 0% to be paid on customer deposits.

7. Accumulated Deferred Income Taxes

The Companies note that inclusion of Plant in Service in rate base is subject to reduction for the applicable associated ADIT. The final ADIT balances presented by the Companies are $(79,725,000) for North Shore and $(520,978,000) for Peoples Gas, adjusted for deferred taxes associated with incentive compensation and Net Operating Losses ("NOLs"), as discussed below. This subject is uncontested with the exception of ADIT as a derivative impact of the items discussed in Sections IV.C.1.a and IV.C.3 below. The Commission approves the final ADIT balances as presented by the Companies.

a. Incentive Compensation

The Companies have agreed to remove, from rate base, the ADIT related to the capitalized incentive compensation costs previously disallowed by the Commission. This is not contested. The Commission approves removal from rate base of the ADIT related to the capitalized incentive compensation costs previously disallowed by the Commission.

b. Net Operating Losses

The Companies and Staff agree that the stand-alone federal NOLs and the related federal deferred tax assets ("DTAs") balances at the end of calendar year 2014 and test year 2015 are zero, and, therefore, the average rate bases used for the test year should not include any NOLs or DTAs. These items are not included in the Companies' rate bases. This subject is uncontested and is approved by the Commission.

c. Derivative Impacts (other than in Section IV.C.1.a)

The Companies note, and the Commission agrees, that the only contested issues related to ADIT are the derivative impacts on ADIT of the items discussed in Sections IV.C.1.a and IV.C.3 below.

8. Customer Deposits

The Companies note that Customer Deposits may be a component (reduction) of rate base when they provide a source of capital. The Companies' original projected balances of Customer Deposits were $(1,996,000) for North Shore and $(23,657,000) for Peoples Gas, based on actual per book data and projected data as applicable. In addition, the Companies accepted Staff's recommended adjustment to reflect the use of the Commission's ordered interest rate of 0% to be paid on customer deposits. This subject is uncontested. The Commission approves the Companies' Customer Deposit balances and the use of the interest rate of 0% to be paid on customer deposits.

9. Customer Advances for Construction

The Companies note that Customer Advances for Construction may be a component (reduction) of rate base when they provide a source of capital. The Companies proposed a credit balance for this item of $562,000 for North Shore and a credit balance of $1,494,000 for Peoples Gas, based on actual per book data and projected data as applicable. This subject is uncontested. The Commission approves the Companies' Customer Advances for Construction credit balances.

10. Reserve for Injuries and Damages

The Companies note that the Reserve for Injuries and Damages may be a component (reduction) of rate base when it provides a source of capital. The Companies proposed a credit balance of $1,082,000 for North Shore as the projected balance for the Reserve for Injuries and Damages at December 31, 2014, and December 31, 2015. North Shore noted that it is not projecting any amounts assumed to be reimbursed by insurance companies.

For Peoples Gas, the Companies proposed a credit balance of $7,615,000 as the projected balance at December 31, 2014, and a credit balance of $7,613,000 as the projected balance at December 31, 2015, for an average of $7,614,000. Peoples Gas noted that beginning in 2012, amounts related to claims that were expected to be reimbursed from insurance companies were recorded by increasing the reserve for injuries and damages and recording an offsetting accounts receivable from the insurance company.

This subject is uncontested. The Commission approves the credit balances for 2014 and 2015 for North Shore and for Peoples Gas.

C. Potentially Contested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Plant

a. 2014 AMRP Additions (including derivative impacts on Accumulated Depreciation and Accumulated Deferred Income Taxes) and Associated Cost of Removal (PGL)

Companies' Position

Peoples Gas argues that its 2014 AMRP costs and the associated costs of removal should be adopted. As background Peoples Gas explains that in fiscal year 1981, Peoples Gas decided to replace its predominantly cast iron and ductile iron main system with cathodically protected steel and plastic main. In that year, cast iron and ductile iron main represented 3,450 miles out of the total of 4,031 miles of main in Peoples Gas' distribution system, or 86%. A 1981 study recommended replacement in certain soil types by 2030, but updates to the study concluded it would be reasonable and prudent to complete all main replacement by 2050. Peoples Gas later determined, however, that acceleration of the program would be beneficial, and the Commission agreed.

In the Companies' 2009 rate cases, Docket Nos. 09-0166/09-0167 (Consol.), the Commission approved a rider that, in brief, would allow Peoples Gas to recover incremental costs of accelerating its cast iron and ductile iron main replacement program. The Commission found that the benefits of accelerating the program include increased safety for the public and Peoples Gas crews, construction and Operating and Maintenance cost savings, creation of jobs, reduction in environmental impacts, and increased functionalities. In 2013, Section 9-220.3 of the Act, 220 ILCS 5/9-220.3, was enacted to allow rider recovery of qualifying infrastructure plant, which includes (but is not limited to) accelerated main replacement costs.

Peoples Gas details that there are four main system upgrade goals for AMRP: (1) to retire 1,870 miles of cast iron/ductile iron gas distribution mains, (2) to upgrade approximately 300,000 service pipes, (3) to relocate gas meters from inside of customer facilities to outside, and (4) to upgrade the gas distribution system from a low pressure to a medium pressure system. Peoples Gas adds that it uses a Main Ranking Index ("MRI") to decide which mains to replace. The Companies state that AMRP is coordinated with the City of Chicago and has extensive management oversight. Peoples Gas notes that their primary witness related to the AMRP, David Lazzaro, is a General Manager of District Field Operations for Peoples Gas, is a highly experienced engineer, and is responsible for all gas distribution utility field operations in the Peoples Gas Central District, including customer service, distribution system maintenance, and construction.

Peoples Gas notes that the AG, in direct testimony, proposed huge reductions in the forecasted 2014 AMRP additions (including the associated costs of removal), *i.e.*, a reduction in the 2014 AMRP additions of a gross $172,651,000, plus another $27,391,000 for the associated costs of removal (the adjustments also have derivative impacts on accumulated depreciation, ADIT, and depreciation expense). According to Peoples Gas, this proposal was based on simply extrapolating from data on actual costs from January through May 2014.

Peoples Gas explains that Mr. Effron's education is in economics, business administration, and accounting. He has spent over 25 years as a regulatory consultant. Before that, he worked for two years as a "supervisor of capital investment analysis and controls" for the conglomerate Gulf & Western Industries and before that for two years as a consultant and staff auditor at an accounting firm. Peoples Gas states that Mr. Effron is not an engineer and he does not appear to have any experience managing a utility capital project or any other infrastructure project.

Peoples Gas argues that Mr. Effron's direct testimony proposal made no sense and was wrong, because, among other things, his simplistic extrapolation from the first five months of 2014 failed to take into account the effects of the unusually cold winter weather on the pace of construction, failed to take into account plans to remediate those delays, and failed to take into account the annual construction cycle, basically missing the peak construction season. According to Peoples Gas, Mr. Effron's proposal also included errors in calculating the derivative impacts (the accumulated depreciation, ADIT, and depreciation expense impacts) associated with his recommended reductions.

Peoples Gas notes that, in contrast, the Companies, in their rebuttal testimony, presented updated reduced costs of the 2014 AMRP additions (and addressed the associated costs of removal) that: (1) reflected the slowed pace of construction in the beginning of the year; (2) took into account the contractors' plans to remediate some, but not all, of the delays; and (3) factored in the construction cycle. Peoples Gas contends that these are the only reliable numbers in the evidentiary record for these costs. In addition, Peoples Gas maintains that CCI accepts the Companies' figures, as presented in rebuttal testimony, for the 2014 plant balances.

Peoples Gas argues that although Mr. Effron's rebuttal testimony significantly reduced his recommended adjustments, he continued to propose to reduce Peoples Gas' 2014 AMRP costs by a gross $65,877,000 plus another $17,231,000 for associated costs of removal (the adjustments also have derivative impacts on accumulated depreciation, ADIT, and depreciation expense). This proposal is based on simply extrapolating from data on actual costs from January through July 2014. Peoples Gas points out that as a result, the AG's rebuttal proposal does not cure the fundamental flaws of the earlier simplistic extrapolation, although the addition of two months of data to his extrapolation reduced the size of his recommended adjustment. Further, the Companies' witness noted that: (1) data for August 2014 further showed that Mr. Effron's proposal was unreasonable, *i.e.*, August 2014 AMRP expenditures were $38.5 million; and, (2) expected expenditures for the four remaining months of the year are $25 million to $30 million per month. Peoples Gas also states that, setting aside the merits of the primary proposed adjustments, the derivative adjustments Mr. Effron calculated in rebuttal were less inaccurate than those in his direct testimony proposal, but they still were incorrect. Peoples Gas mentions that Staff agrees with the Companies' corrections to the AG's calculations of the derivative impacts.

Peoples Gas notes that while the AG's briefing (like its cross-examination at the evidentiary hearing) focuses on confirming the correctness of figures for actual capital expenditures on AMRP for January through August 2014, the capital expenditure "actuals" do not support the AG's proposals. Peoples Gas emphasizes that the numbers it presented in rebuttal testimony take into account the delays due to weather, the contract plans to reduce some of those delays, and the construction cycle. In addition, Peoples Gas notes that while the AG's rebuttal proposal is based on capital expenditures through July 2014, the AG's Initial Brief shows that in August 2014, actual AMRP capital expenditures were $38,465,000, which is $6,349,000 above the budgeted figure for that month, $32,116,000. However, as the Companies emphasize, even though August was more than $6 million above the budget for that month, the AG made no modification to reduce its proposed adjustments. Peoples Gas contends that the August data is consistent with Peoples Gas' rebuttal figures, not the AG's proposal. Peoples Gas further states that the AG's arguments also effectively ignore the contractors' plans to make up in part for the delays earlier in the year, and disregard the Companies witness' testimony regarding opportunities that developed after the revised budget was prepared.

The AG also argues that according to Companies witness Mr. Lazzaro's testimony, the expected AMRP expenditures for the last four months of the year are $25 million to $30 million per month, which are contrary to the revised budget's figures for those months. However, Peoples Gas emphasizes that the AG's argument again ignores the fact that August 2014 expenditures were more than $6 million over the revised budget, ignores the contractors' plans to make up in part for the delays earlier in the year, and disregards Mr. Lazzaro's testimony regarding opportunities that developed after the revised budget was prepared. Further, Peoples Gas notes that the AG complains that when the Companies' witness Mr. Lazzaro testified about the opportunities that developed after the revised budget was proposed, he did not explain them in more depth. In response, Peoples Gas emphasizes that this was cross-examination, and the AG did not ask Mr. Lazzaro to do so. Rather, the AG stopped its cross-examination of Mr. Lazzaro at that exact point.

Peoples Gas contends that the AG's proposal to adjust costs of removal associated with AMRP based on January through July 2014 actual costs lacks merit for the same reasons as the proposal to reduce AMRP costs, with one exception. Peoples Gas explains that here, inconsistently, the AG points to the fact that August 2014 data also was under the revised budget, and Peoples Gas argues that the AG cannot have it both ways. The AG cannot claim that the August removal costs being almost $1 million under the budget supports its proposal, while the August AMRP costs being over $6 million over the budget somehow is irrelevant and does not undercut its proposal.

In addition, Staff's own cross-examination exhibit shows that August 2014 AMRP additions were $27,364,786.36. Staff Group Cross Ex. 1 at Peoples Gas' response to Staff data request ("DR") DLH 34.04. Peoples Gas argues that the evidence supports the Companies' rebuttal figures and negates the AG's proposal and the Staff witness' speculation.

Peoples Gas notes that Staff witness Ms. Hathhorn's rebuttal testimony stated that Staff would support the direct testimony version of the AG's proposal, subject to the AG's direct testimony proposal being updated and corrected. In addition, Peoples Gas offers that Staff provided no testimony that addressed the merits of any version of the AG proposal, apart from Staff's speculation that Peoples Gas' rebuttal's reduced figures did not appear attainable.

Peoples Gas finds that Staff's support of the AG's proposal is based primarily on figures for QIP additions (which includes both AMRP additions and the uncontested revised costs of the Calumet project), less retirements. Peoples Gas adds, however, that Mr. Effron's rebuttal proposals are based on his analysis of capital expenditures (not additions), and do not factor in retirements.

Peoples Gas claims that Staff's discussion, by focusing on additions and not expenditures, fails to take into account the large amount of 2014 AMRP expenditures that already have been incurred but have not yet been recorded as additions.

Peoples Gas states that on October 17, 2014, Staff filed a motion that the Commission take administrative notice of an existing filing relating to September QIP additions and related data and certain future filings relating to QIP additions and related data. The Companies filed a response on October 29, 2014, in which they did not object to Staff's motion but they expressed concerns with how the information might be used by the Commission and regarding its selectivity (providing update information regarding one area of costs but no others, such as paving costs, which are increasing). Staff filed a reply on November 3, 2014, that accepted the Companies' caveats about use of the information and did not discuss the subject of selectivity. On November 5th, the Administrative Law Judges granted Staff's motion, and incorporated certain caveats. The Companies state that the data in the attachment to Staff's motion does not support the AG's proposal.

As well, Peoples Gas argues that Staff's assertion that the Companies are using their concern about the cap in Rider QIP as a reason to include an excessive amount of 2014 AMRP and associated removal costs in rate base is incorrect. Peoples Gas contends that the AG and Staff are using Rider QIP as a failsafe to argue that the Commission should not worry about excessive rate base reductions here because the rider will fix them. Peoples Gas emphasizes that the Companies are not arguing that anything about the rider means that the Commission should approve any rate base figure that the evidence shows to be too high, but that the Companies are arguing that the facts in evidence show that their rebuttal figures are the only reliable figures.

Peoples Gas notes that the AG's witness also has suggested that, if his proposed adjustment to 2014 AMRP and associated removal costs turns out to be incorrect, then the mechanism of Rider QIP will correct for the error. According to Peoples Gas, the Staff witness appeared to accept that reasoning. Peoples Gas argues that this reasoning is a highly problematic over simplification. If the Commission reduces the 2014 AMRP costs and related removal costs as urged by the AG (and Staff), and it turns out that 2014 costs are higher than Mr. Effron speculated they will be, then the amount of QIP investment that Peoples Gas can make and recover under Rider QIP while staying within the annual average revenue cap in 2015 (and in all subsequent years until new base rates are set and in effect) will be reduced. As a result, that could potentially adversely impact future QIP projects, mainly the AMRP, unless Peoples Gas was to file another rate case.

Peoples Gas submits that there is only one reasonable set of figures for 2014 AMRP additions and the associated costs of removal, which are reflected in the Companies' rebuttal testimony. Peoples Gas contends that the reduced 2014 AMRP costs figures (including the removal costs), as reflected in rebuttal testimony, should be adopted.

The foregoing discussion of Peoples Gas' position is subject to the alternative proposal made by the utility in its Brief on Exceptions, in the interests of narrowing the issues. Peoples Gas, in the alternative, proposed to update the 2014 AMRP costs, and the associated costs of removal (and the Calumet system upgrade project costs), based on (1) the actual additions and removals data through November 2014 filed by the Utilities and made part of the record in this case pursuant to a Staff motion granted by the Administrative Law Judges and (2) Peoples Gas' estimates for December 2014 as of its rebuttal testimony.

Staff's Position

Staff recommends that the Commission adopt the AG's revised adjustment to Peoples Gas' 2014 AMRP additions that also qualify as Rider QIP additions, so that rate base is set at a reasonable level, rather than the Company's forecast which appears unattainable. Staff notes that the amount of AMRP additions included in rate base will be adjusted to actual costs through the Rider QIP surcharge. Therefore, Staff finds that the primary impact of the 2014 AMRP Additions adjustment will be its impact on base rate revenues for purposes of the future Rider QIP cap.

Staff maintains that while the Company did reduce its 2014 forecasted additions for AMRP and the Calumet Pipeline Project in rebuttal testimony, the record shows that the Company's forecast is still not reasonable. Peoples Gas has added approximately $51 million in additions through August 2014. Staff asserts that the Company would need to place in service more than double that amount in September through December 2014 in order to attain its forecast of $173 million. The Company would have to invest more than $100 million in just three months to hit its forecast.

Staff adds that Rider QIP contains a revenue cap at Section 9-220.3(g) of the Act, which limits increases billed under Rider QIP to an annual average of 4% of base rate revenue, not exceeding 5.5% in any given year. The Company is concerned that if the appropriate 2014 AMRP additions amount is not included in the approved base rate revenue, the amount of QIP investment that can be recovered under Rider QIP after new rates become effective as a result of this proceeding (2015 and subsequent years) will be impacted. Staff emphasizes that everything from this case which impacts base rate revenues will affect the new Rider QIP revenue cap, not just the level of Rider QIP additions allowed in rate base. Further, the existence of the cap is not adequate justification to allow rates that include an unreasonable amount of rate base. Base rate revenues should determine the cap. The Company's position would flip that and have the cap determine base rate revenues. Staff concludes that this proposal by the Company is neither just nor reasonable.

In its Brief on Exceptions, Staff discussed the updated evidentiary record reflecting the October 2014 AMRP plant additions, and noted that since the ALJs granted administrative notice, the November and December 2014 data may be considered by the Commission in deciding this issue.

AG's Position

The AG explains that in order to determine the forecasted test-year utility plant included in rate base, the Companies began with the actual balances of plant for 2013 and then adjusted those balances for forecasted additions to and retirements from plant for calendar years 2014 and 2015. Peoples Gas included actual and forecasted 2014 QIP additions in its 2015 test-year rate base, and depreciation on those 2014 QIP additions in 2015 test-year expenses. However, Peoples excluded its 2015 QIP net investments, which will be recovered in 2015 through Rider QIP, from any test-year calculations. AG witness Mr. Effron sought to estimate actual PGL AMRP capital expenditure for 2014 as reasonably and accurately as possible. Through his estimation, Mr. Effron found that PGL's forecast of total 2014 AMRP capital expenditure is inflated and must be reduced.

The AG notes that in a discovery response prior to Mr. Effron's rebuttal testimony, Peoples Gas provided figures on actual AMRP expenditure (which includes additions plus construction work in progress, or "CWIP") for January through July of 2014, which made the average monthly expenditure for those seven months approximately $14.3 million, translating to a twelve-month total of $171.559 million. Meanwhile, Peoples is forecasting a total of $237.436 million in 2014 AMRP capital expenditure.

The AG states that Mr. Lazzaro confirmed during cross-examination that for all seven months of January through July, 2014, the actual amount of AMRP expenditure was below the budgeted amount. The AG continues that high spending in August 2014 can be understood because summer is the "peak" season for construction, but summer is now over, and we should not expect that actual spending in the final four months of 2014 will equal budgeted capital expenditure. The AG maintains that in light of the Company's poor track record of actually spending up to its budget on the AMRP program, the Commission should not give weight to the Company's optimistic projections for the remaining months of 2014.

The AG continues that in light of this large discrepancy between actual spending and budgeted spending, Mr. Effron thus proposed reducing the 2014 AMRP expenditures included in PGL's test-year rate base accordingly, from the Company's forecast of $237.436 million to the more reasonable forecast of $171.559 million – a downward adjustment of $65.877 million. He also proposed correspondingly reducing the PGL 2015 test-year depreciation expense by $2.365 million which include Mr. Effron's adjustment to 2014 forecasted cost of removal.

The AG explains that there is no risk to PGL of any possible under-measurement of its 2014 AMRP capital expenditure, because, as Peoples indicated in testimony, if actual 2014 QIP additions are greater than the amount approved in base rates through this proceeding, Peoples Gas will recoup the difference through the first Rider QIP filing after base rates pursuant to this proceeding go into effect in early 2015, so the Company faces no risk of under-recovery.

The AG asserts that doubling down on the Company's overly optimistic projections for the remainder of 2014 shown at AG Cross Exhibit 9, Mr. Lazzaro stated in surrebuttal testimony that it is expected that the expenditures for the rest of the year will be $25.0 to $30.0 million per month without giving any justification for the claim. Asked during cross-examination to reconcile these vastly disparate figures, Mr. Lazzaro indicated that PGL did not learn any new information between the times of the August 12 discovery response and the September 12 surrebuttal testimony that caused the Company to increase the budgeted AMRP spending amounts. On the other hand, he indicated that some projects were included that allowed the Company to do additional work later in the year based on opportunities presented by the City and based on weather. The AG contends that Mr. Lazzaro did not, however, attempt to explain these alleged "opportunities" in any more depth or show how the budgeted amounts as of August 12 could double or more than double in just a month's time. The AG submits that the sudden and drastic change in the Company's forecasted AMRP monthly expenditures lacks credibility and should not serve as a basis for the Commission to approve the Company's forecast. The AG asserts that if the August 12 budget is difficult to believe, the "$25.0 to $30.0 million" forecast in Mr. Lazzaro's surrebuttal testimony is even more outlandish. The AG concludes that the Commission should approve Mr. Effron's downward adjustment to 2014 AMRP capital expenditure to be included in rate base.

Further, the AG states that Mr. Effron proposes modifying the cost of removal related to 2014 QIP property in line with his proposed modification to forecasted 2014 AMRP additions. As of rebuttal testimony, Mr. Effron proposed reducing the PGL forecast of $34.353 million of 2014 AMRP cost of removal to $17.122 million, in line with the actual AMRP cost of removal for the first seven months of 2014. The rate base effect of this adjustment is $10.136 million.

In surrebuttal testimony, AG witness Mr. Lazzaro suggested that, similar to his arguments on 2014 AMRP expenditures, the expenditures related to AMRP cost of removal will also increase to reflect the peak months of construction in 2014 and thus no adjustment is appropriate. The AG argues, however, for the same reasons as estimated AMRP capital expenditures lack credibility, his statement on the related cost of removal cannot be taken seriously.

Mr. Lazzaro confirmed during cross-examination that for all seven of the months of January through July of 2014, the actual cost of removal shown on PGL Exhibit 38.1 was below the actual cost of removal shown on AG Cross Exhibit 9. He also agreed that the actual cost of removal for August 2014 was approximately $1 million below the budgeted cost of $3.2 million. The AG argues that in light of the Company's consistent discrepancies between actual and budgeted cost of removal for AMRP, the Commission should approve Mr. Effron's proposed downward adjustment to 2014 AMRP cost of removal.

In summary, the AG states that the total rate base effect of Mr. Effron's proposed adjustment to PGL's forecasted 2014 AMRP additions is to reduce test-year rate base by $72.843 million. Additionally, Mr. Effron's proposal reduces PGL's 2015 test-year depreciation expense by $2.365 million. The AG offers that in light of the Company's consistent failure to spend up to budgeted amounts, the Commission should not simply take the Company's promises of late-year 2014 spending at face value.

Commission Analysis and Conclusion

The Commission approves Peoples Gas' proposal to update the 2014 AMRP costs and the associated costs of removal, and the Calumet system upgrade project costs, as proposed in the Utilities' Brief on Exceptions. The "middle ground" proposal was accepted by both the AG and Staff in their Reply Briefs on Exceptions. The proposal is based on a reasonable methodology of annualizing actual data on net plant additions for January through November of 2014 that was entered into the record as well as Peoples Gas' December 2014 costs as previously estimated in its rebuttal.

The Commission has acknowledged the importance of the Peoples Gas AMRP project, has prioritized the acceleration of the program, and notes the varied benefits for customers that will arise out of this program. Pursuant to 220 ILCS 5/9-220.3, Peoples

Gas is entitled to allowed rider recovery of qualifying infrastructure plant, including accelerated main replacement costs, but the 2014 costs at issue will become part of rate base here, and no longer recovered under the rider.

Peoples Gas will recover its actual prudent costs of AMRP additions by use of an adjustment through Rider QIP. However, although the revenue cap restriction on Rider QIP that will be set in this case pursuant to Section 9-220.3(g) of the PUA does not prohibit Peoples Gas from filing for rate recovery under a traditional rate case should the cap restriction begin to influence Peoples Gas' AMRP progress, this Order in its ruling on the subject of rate case expense amortization, Section V.C.4 of this Order, assumes that the Commission will approve the proposed WEC-Integrys transaction in the pending reorganization approval Docket and, further, will approve a proposed commitment not to file for rates that will be effective for before two years from the closure of the transaction. If the reorganization is approved, therefore, Peoples Gas might be precluded from filing for rate recovery to alleviate the restrictions placed on Peoples Gas' AMRP progress by the revenue cap. Thus, it is essential to approve the most reasonable figures for these costs, which are found in the Peoples Gas updates.

2. Cash Working Capital

a. Other Post Employment Benefits (OPEB) lead

<u>Companies' Position</u>

The Companies explain that CWC essentially is the amount of funds (positive or negative) required to finance the day to day operations of a utility, and that the CWC requirement is included in each of the Companies' rate bases for ratemaking purposes. To determine the CWC requirement, a lead-lag study analyzes the differences between the revenue and collection lags and the expense leads of a utility in order to measure and quantify the impact and timing of the utility's cash flow. The Companies further explain that three broad categories of leads and lags are considered in such a study: (1) lag times associated with the collection of revenues owed to the utility; (2) lag and lead times associated with the collection and payment of what are commonly called "pass-through" taxes and "energy assistance charges"; and (3) lead times associated with the payment for goods and services received by the utility. The Companies state that, in order to determine the leads and lags in the CWC analysis, the Companies utilized data from the Companies' Accounts Payable, Customer Service, Payroll, General Ledger, and Tax Systems, as well as records from the Companies' bank accounts. As discussed in Section IV.B.3 above, the Companies' CWC figures are not contested, apart from the figures for the OPEB lead and any derivative impacts of contested operating expense adjustments that affect the applicable inputs to the CWC calculations.

The Companies state that, based on an analysis of payments to a trust for OPEB during calendar year 2012 (the last full year for which data was available at the time the CWC lead-lag studies were prepared), the Companies calculated lead expenses of negative 66.64 days for North Shore and negative 99.09 days for Peoples Gas.

The Companies note that the use of a lead-lag study to calculate the Companies' CWC requirement is not contested. However, Staff contests the Companies' OPEB expense lead, arguing that the Companies' cash payments for OPEB during calendar year 2012 were not made in accordance with "normal practice," and that a payment date of December 18, 2012, is more reasonable than the Companies' January 9, 2012, payment date. Based on this adjustment, Staff argues that the OPEB CWC factor should be adjusted to a positive lead of 170.00 days for North Shore and a positive lead of 169.91 for Peoples Gas.

The Companies argue that Staff's proposal to reject the actual cash flow data from 2012 relating to the OPEB leads and to substitute hypothetical later payments is flawed, inconsistent with the Staff position adopted by the Commission in prior rate cases, and one-sided. The Companies assert that their OPEB leads are based upon the most recent calendar year data that were available at the time the lead-lag studies were conducted, and that in accordance with customary practice, the Companies considered the timing of all of the payments made during the year and dollar weighted them, resulting in proposed negative lead values of 66.64 for North Shore and 99.09 for Peoples Gas.

The Companies argue that Staff's adjustment is based solely on its subjective opinion that a payment made at the end of the year is more appropriate than a payment made at the Company's discretion, when funds were available. The Companies note that Staff admits that the OPEB trust payments did not have specific due dates. According to the Companies, Staff bases its adjustment on a limited historical view of the Companies' OPEB payments, arguing that, based on payments made in 2013 and pending payments in 2014, it appears the normal practice is to pay in December. The Companies contend that in two out of the last three full calendar years, the Companies made OPEB payments very early in the year. The Companies argue that Staff's assertion that the Companies' OPEB trust payments were inconsistent with "normal practice" is unsupported and based on a subjective and selective evaluation of the Companies' historical practices, and that Staff's adjustment should be rejected.

The Companies further note that Staff's position is inconsistent with its position taken in Docket Nos. 12-0511/12-0512 (Consol.), during which Staff argued that the OPEB lead should be set at the intercompany billing lead. Docket Nos. 12-0511/12-0512 (Consol.), Order at 80; NS-PGL Ex. 22.0 REV at 6-7. In the instant proceeding, the Companies note, Staff does not propose to continue the use of the intercompany billing lead, but instead bases the adjustment to the OPEB Expense Lead on the cash flows provided by the Companies during calendar year 2012 as adjusted by Ms. Hathhorn. This adjustment results in lead changes from negative to positive, resulting in a decreased CWC. The Companies argue that Staff has offered no valid justification for this inconsistency.

Further, the Companies argue that Staff bases its adjustment on an inapposite and irrelevant Commission Order in an unrelated docket. The Companies explain that Ms. Hathhorn cited to the Commission's final Order in an Ameren Illinois Company ("AIC") docket, Docket No. 13-0192, arguing that the Commission previously ruled that CWC factors should be calculated based on payment due dates rather than internal policies. According to the Companies, this argument is unsupported and unrelated to the issue of OPEB trust payments made in the absence of any specific due dates. In ICC Docket No. 13-0192, the Commission examined challenges to AIC's payment of pass-through taxes based on billing dates rather than collection dates, in contravention of statutory due dates or due dates prescribed by municipal ordinances. *Ameren Illinois Company d/b/a Ameren Illinois*, Docket No. 13-0192, Order at 15-20 (Dec. 18, 2013). In adopting the proposals propounded by Staff and various intervenors, the Commission noted that "AIC's practice of remitting pass-through taxes earlier than required increases rate base by increasing CWC." *Id.* at 19. The Companies emphasize that, in clear contrast to the AIC docket, the OPEB trust payments at issue in the instant proceeding have no required due date, either through statute, municipal ordinance, or prior Commission decision, and argue that Staff's reliance on Docket No. 13-0192 as support for its adjustment is misplaced and should be rejected.

The Companies further point out that the lead-lag studies are based on data that consists of hundreds of thousands of cash transactions, and that Staff has shown no sound reason to modify only the OPEB lead payment dates, particularly when that would result in significantly reducing the cash working capital available to meet day-to-day operational needs.

The Companies contend that Staff's proposal also is incorrect because the OPEB liability already is a rate base deduction, meaning the lead should be zero days, and making Staff's proposal a double-counted reduction to rate base, although the Companies recognize that the Commission did not adopt their view that the lead should be zero days in Docket Nos. 12-0511/12-0512 (Consol.).

Finally, the Companies argue that Staff's proposal is one-sided. Customers have the benefit of the actual payment date in the form of reduced OPEB expenses that resulted from the actual payment date (the "early" payment according to Staff) being included in the calculation of operating expenses in the Companies' revenue requirements. OPEB expenses, all else being equal, are reduced by contributions to the OPEB trust and the earnings on the assets resulting from those contributions. According to the Companies, the Staff position would deny the Companies the time value of the actual payment date, while giving customers the benefit of the actual payment date, which is unfair and unreasonable.

The Companies note that, in its Initial Brief, CCI expressed support for Staff's position based wholly on Staff arguments. The Companies conclude that Staff's proposal, as supported by CCI, should be rejected and that the Companies' CWC figures should be approved.

<u>Staff's Position</u>

Staff and the Companies agree on the methodology to update CWC for the final revenue requirements ordered by the Commission in the instant cases, and for all leads and lags except for the expense lead for pension and OPEB. Appendices A and B to Staff's Initial Brief, use an OPEB payment date in December, rather than January as used by the Companies, because the OPEB December payment date appears more reasonable in light of past payments by the Companies. This results in an OPEB positive lead of 170.00 days in the CWC calculation for North Shore, rather than a negative expense lead of (66.64) days, and a positive lead of 169.91 days in the CWC calculation for Peoples Gas, rather than a negative expense lead of (99.06) days, because it is not reasonable to base the 2015 future test year on the early payment date that occurred in 2012.

The Companies opine that because the OPEB payments do not have a statutory due date, a payment cannot be deemed early or late. Staff disagrees and points to the historical OPEB payment activity. Staff's position is that basing the expense lead for OPEB in the CWC calculation based upon the Companies' past payment practice for OPEB for one of the last six years is not prudent or reasonable. Staff asserts that the early OPEB trust fund payments of $7.5 million for North Shore and $67.5 million for Peoples Gas, combined with the payment made so early in the calendar year, actually creates a negative lead or a revenue lag. Staff maintains that the Companies' position creates a higher CWC and rate base than is necessary when using their customary payment practice.

Staff notes that the Commission has previously ruled that CWC and rate base should not be increased when Companies pay expenses earlier than necessary. For instance, in Docket No. 13-0192, AIC proposed that the expense leads for its pass-through taxes be set based on the amount of time AIC holds the funds before remittance. However, in Docket 13-0192, Staff, the AG and CUB proposed that the calculation be instead based on when the taxes are due, consistent with prior Commission Orders in Docket Nos. 12-0001, 12-0293, 11-0721, and 12-0321. Staff submits that the Commission agreed with Staff, the AG and CUB:

> The Commission agrees with Staff and AG/CUB that their proposal is consistent with recent Commission Orders and will protect ratepayers from incrementally higher rates attributable to the utility's practice of remitting taxes earlier than they are due. As Staff points out, AIC's practice of remitting pass-through taxes earlier than required increases rate base by increasing CWC.

Docket No. 13-0192, Order at 19.

Staff reasons that the AIC Order addressed pass-through taxes having a statutory due date while in this proceeding, the OPEB payments do not have a statutory due date. But, like AIC, the Companies are proposing an earlier payment date than required that unnecessarily and unreasonably increases rate base. Staff continues that because the OPEB trust fund payments do not have a set due date, the CWC factor should be based on the Companies' normal payment policy date of December, consistent with the Commission's position that early payments should not result in increased rate base to rate payers.

<u>CCI's Position</u>

CCI supports Staff witness Ms. Hathhorn's proposal to use a December payment date for OPEB rather than a January payment date (as proposed by the Companies) in calculating the related CWC requirement. As Ms. Hathhorn noted, in four of the last six years, the Companies made their largest OPEB payment in December. CCI states that in only one of the past six years was the Companies' largest OPEB payment in January.

CCI argues that assuming an anomalous January payment date instead of a December payment date serves to increase the Companies' rate base. CCI stresses that the Commission must carefully examine the record evidence in considering when the Companies are most likely to actually make their OPEB payment in the 2015 test year. According to CCI, the manifest weight of the evidence points to a December payment date as the most reasonable for ratemaking purposes.

CCI concludes that the Commission should approve Ms. Hathhorn's proposal to use an OPEB positive lead of 170.00 days in the CWC calculation for NS and a positive lead of 169.91 days in the CWC calculation for PGL.

Commission Analysis and Conclusion

The Commission agrees with Staff and CCI and approves an OPEB positive lead of 170.00 days in the CWC calculation for North Shore and a positive lead of 169.91 days in the CWC calculation for Peoples Gas. Considering the historical OPEB payment activity and the lack of a required payment date, the Commission finds that it is not reasonable to base the 2015 future test year on the early payment date that occurred in 2012. It is the Commission's position that CWC and rate base should not be increased when utilities pay expenses earlier than necessary.

3. Retirement Benefits, Net

Companies' Position

The Utilities recognize that the Commission, in the Utilities' 2007, 2009, 2011, and 2012 rate cases, found that: (1) the Peoples Gas pension asset (and the North Shore pension liability or asset, as applicable) should not be included in the calculation of rate base; and (2) the Utilities' OPEB liabilities nonetheless should be included in the calculation; and (3) that the Docket Nos. 09-0166/09-0167 (Consol.) Order was affirmed on appeal on this subject. *North Shore Gas Co./The Peoples Gas Light and Coke Co.*, Docket Nos. 09-0166/09-0167 (Consol.) (Jan. 21, 2010). While the Utilities agree with the Commission's past findings that, if a pension asset is excluded, then a pension liability also should be excluded, the Utilities respectfully request that the Commission reconsider whether to include Peoples Gas' pension asset in the instant proceeding, and, alternatively, whether to include specific pension liabilities in rate base or to exclude amounts related to pensions. Also, the Commission should reject Staff's proposal to exclude the Peoples Gas pension asset from rate base while including the North Shore pension liability, which is contrary to the Orders in Docket Nos. 07-0241/07-0242 (Consol.) and Docket Nos. 09-0166/09-0167 (Consol.). *North Shore Gas Co./The Peoples Gas Light and Coke Co.*, Docket Nos. 07-0241/07-0242 (Consol.) (Feb. 5, 2008)

Using average rate base, as updated in rebuttal testimony, North Shore's pension liability is $(8,000), and Peoples Gas' pension asset is $17,350,000. NS-PGL Ex. 22.9N, line 11, col. (G); NS-PGL Ex. 22.9P, line 11, col. (G).

The Utilities explain that the Commission's past decisions to exclude the Peoples Gas pension asset (and, when applicable, North Shore's) from rate base were based on findings that the asset is, or at least has not been shown not to be, the product of customer-supplied funds. *E.g.,* Docket Nos. 07-0241/07-0242, Order at 36. The Utilities note that Staff advances that same position in the instant cases, while the AG simply proposes to apply the prior Commission decisions.

The Utilities argue that the Commission should reconsider approving inclusion of the pension asset(s) in rate base for several reasons. First, the premise that customers, by paying utility bills, should be treated as if they had paid for the utility's assets, is incorrect as a matter of law. Customers pay for service, not for the property used to render it. *Board of Pub. Utility Commissioners, et al. v. New York Tel. Co.*, 271 U.S. 23 (1926). Second, the pension asset is part of the utility's balance sheet and, with respect to defined benefit plans, the utility owns the assets via the trust that holds the assets, with the employees being the beneficiaries of the trust.

Third, the rates on which customers' bills are based reflect the accrual of pension expense. The Utilities submit that although Staff claims that customers paid for the pension asset (and the AG does so implicitly by citing past Orders to that effect), Staff does not explain how customers supposedly pay for the pension asset, and, specifically, does not refute the fact that the bills customers pay are based on the accrual of pension expense. The Utilities assert that a pension asset exists when cumulative funding exceeds the cumulative amount of recognized pension expense. The Utilities contend that customers did not pay for the excess by which cumulative pension funding exceeds cumulative recognized pension expense, which means that they did not pay for the pension asset. In addition, the Utilities state that the rates upon which customers' bills are based reflect the accrual of pension expense. The Utilities note that Staff simply argues that pension assets are created with funds supplied by customers, and that the Utilities have not provided evidence to distinguish this case from prior Commission rulings, yet fails to provide any new evidence to support its claims.

Fourth, the Utilities maintain that normal operating revenues of a utility include amounts collected through rates to repay the utility's cost of capital, and the portion of amounts collected from customers that end up as net income is retained earnings, and thus is part of shareholders' equity, to the extent it is not paid out in dividends. The Utilities note that Staff admitted that the pension asset is funded by normal operating revenues. The Utilities emphasize that the evidence demonstrates that funds from normal operations include repayment of the utility's cost of capital, so the utility's use of that repayment for pension funding does not mean that the funding is not capital of the utility. In addition, the Utilities contend that Staff's reasoning is inconsistent. When the subject at hand is whether incentive compensation costs should be recovered, and the metric is net income, Staff contends, and the Commission has agreed, that the metric is "shareholder-oriented". Yet, here, where it has been shown that the prepayment of pension expense is a reduction to net income and retained earnings, Staff contends that the funds in question are customer-supplied.

Fifth, the Utilities argue that cumulative pension contributions have exceeded cumulative recognized Generally Accepted Accounting Principles ("GAAP") pension expense. The Utilities note that Staff has not disputed this point.

The Utilities find that in the instant proceeding, Staff has only offered a limited response to the Utilities' point regarding the normal operating revenues of a utility, asserting that the facts between the instant proceeding and the prior Commission Orders are unchanged and that the Utilities' arguments are based solely on theoretical contributions. However, the Utilities argue, Staff continues to fail to provide a sound reason those particular points are incorrect or do not support the inclusion of the pension assets in rate base. Thus, the Utilities contend that the Commission has sufficient grounds for reconsidering this issue and note that the decision should be based on the evidence in the record of the instant Dockets. 220 ILCS 5/10-103; 220 ILCS 5/10-201(e)(iv)(A).

The Utilities note that the AG's Initial Brief did not respond to or dispute any of the Utilities' points in detail; instead, the AG asserted that the adjustments made by its witness were in accordance with the Commission's previous findings in the past relevant dockets. In addition, the Utilities note that although CCI did not address this issue in testimony, CCI argues that the Commission should adopt the proposal to properly account for pension assets, which are ratepayer funded. CCI simply refers to the past Commission decisions on this topic, and adopts the propositions of Staff and the AG.

Finally, while Staff espouses adherence to the prior Orders as to exclusion of Peoples Gas' pension asset from rate base, Staff's rebuttal inconsistently argues for subtracting the North Shore pension liability, even though that same Staff proposal was rejected in the prior Orders. More specifically, Staff made the same proposal in the Utilities' 2009 rate cases, and the Commission's Order in Docket Nos. 09-0166/09-0167 (Consol.), Order at 36-37 rejected it, just as had occurred in the Utilities' 2007 rate cases, and Staff has not provided any change in circumstances or any basis for a different outcome here. Even the AG's witness opposes the inclusion of the North Shore pension liability in the rate base calculation if the Peoples Gas pension asset is excluded.

Accordingly, the Utilities assert that the Commission (1) should approve the inclusion of Peoples Gas' pension asset and North Shore's pension liability in rate base, or, alternatively (2) should exclude the Peoples Gas pension asset and the North Shore pension liability, the latter being as ordered in Peoples Gas 2007 and Peoples Gas 2009 when one utility had a pension asset and the other had a liability.

Finally, if the Peoples Gas pension asset is not included in rate base, then the Utilities respectfully contend that consistency of reasoning would require removal of the OPEB liabilities from rate base, although the Utilities acknowledge that the Commission rejected that contention in past rate cases.

Staff's Position

Staff submits that disallowances from rate base for the Companies' pension assets and related ADIT are required because the Companies have not demonstrated that they were created with anything other than ratepayer funds. The Commission has repeatedly held that shareholders are not entitled to a return on ratepayer-supplied funds. Staff states that the Companies' criticisms of prior orders of the Commission and Appellate Court do not diminish those rulings.

Staff asserts that Peoples Gas acknowledges that the Commission ruled that its pension asset should not be included in rate base in its last four general rate cases, but continues to argue that inclusion is warranted. Staff notes that North Shore has also not had a pension asset in the last four rate cases. However, Peoples Gas states that its additional grounds for inclusion in rate base in its Docket Nos. 12-0511/12-0512 (Consol.) were not explicitly addressed by the Commission's final Order. Staff responds that Peoples Gas mischaracterizes the Commission's final Order in its 2012 rate case which specifically sets forth all of Peoples Gas' claims for its position (Docket Nos. 12-0511/12-0512 (Consol.), Order at 80-82) and the Commission's conclusion shows that it rejected those claims (*Id.* at 90). Staff adds that the Commission is not required to make a particular finding as to each evidentiary fact or claim made by a party. *United Cities Gas Co. v. Illinois Commerce Comm'n*, 47 Ill.2d 498, 501 (1970).

Peoples Gas criticizes Staff's reliance on the Appellate Court decision arising out of Docket Nos. 09-0166/09-0167 Cons. ("2009 Court Opinion") because the Commission and Court did not specifically refute all the Company's points made in Docket Nos. 11-0280/11-0281 (Consol.) and the 2012 rate cases. Staff offers that while there are still appeals outstanding on the 2011 and 2012 rate cases, the 2009 Court Opinion which rejected the Company's pension asset arguments is still good law.

Staff contends that the evidence presented by the Companies in this case simply does not distinguish this case from prior Commission rulings on the same subject. The Companies provided no evidence that the contributions were made from any source other than normal operating revenues (*i.e.* direct unequivocal contributions from shareholders creating a "pension asset"). The Companies state only that contributions to the pension plan "would be first funded from operating cash flows. If operating cash flows are insufficient, the cash requirements are funded with short-term debt; short-term debt would be replaced as needed by long-term debt and equity to maintain our capital structure. Thus contributions are ultimately funded by capital." Attach. B to Staff Ex. 1.0

Staff submits that prior orders reject any inclusion of a pension asset in rate base for anything other than a specific contribution from shareholders. In Docket Nos. 09-0166/09-0167 (Consol.), the Commission denied inclusion of Peoples Gas' pension asset in rate base because there was no evidence in the record it was created with shareholder funds:

> The Companies have given us no reason to overturn our decision from their last rate case. Although the Companies state that the pension asset was created with shareholder funds, no evidentiary support was provided. The Commission finds no support in the record to allow for the inclusion of Peoples Gas' pension asset in rate base which in turn would allow shareholders to earn a return on ratepayer supplied funds.

Docket Nos. 09-0166/09-0167 (Consol.), Order at 36. The Illinois Appellate Court upheld this order, stating:

> The central issue before us remains whether the Commission's decision to exclude the pension asset, which it found consisted of consumer-supplied funds, from Peoples Gas' rate base was against the manifest weight of the evidence. Both the Staff's and the People's expert witness

> testified the pension asset constituted customer-supplied revenues and, therefore, should be deducted from the rate base calculation.
>
> …
>
> Based on the record before us, we find the Commission's decision with regard to the pension asset deduction is not clearly against the manifest weight of the evidence. Accordingly, we see no reason to disturb the Commission's findings.

Peoples v. Illinois Commerce Commission, Nos. 1-10-0654, 1-10-0655, 1-10-0936, 1-10-179, and 1-10-1846 and 1-10-1852, Consolidated, Appellate Court (First District-Fifth Division) September 30, 2011, at 42-43, par. 69-71.

Staff adds that the Commission denied inclusion of the pension asset in the subsequent two North Shore/Peoples Gas rate cases. *See* generally, *North Shore Gas Co./The Peoples Gas Light and Coke Co.*, Docket Nos. 11-0280/11-0281 (Consol.), Order at 33 (January 10, 2012); Docket Nos. 12-0511/12-0512 (Consol.), Order at 90.

Staff mentions that in three separate gas rate cases, Docket No. 08-0363, Docket No. 04-0779, and Docket No. 95-0219, Northern Illinois Gas Company d/b/a Nicor Gas Company sought to increase utility rate base for the amount of a prepaid pension asset. In all three cases, the Commission found that the pension asset was created by ratepayer-supplied funds, not by shareholder-supplied funds. The Commission concluded that ratepayers should not be denied the benefits associated with the previous overpayment for pension expense which ratepayers funded. Accordingly, the Commission concluded that the pension asset should be eliminated from rate base.

Likewise, in Docket No. 11-0767, the Commission ruled that Illinois American Water Company's proposal to include a pension asset in rate base was not substantively different than those the Commission had considered, and rejected, in past rate case decisions.

Staff states that the only time the Commission has allowed a return on pension plan payments was the identification of a specific contribution from shareholders, not a theoretical contribution as the Company argues here. It is undisputed that the Company has an expected pension contribution of $0 for the test year. Additionally, the return on the specific pension payment previously approved by the Commission was a debt return, not the cost of capital. *Commonwealth Edison Company*, Docket No. 05-0597, Order on Rehearing at 28-29 (Dec. 20, 2006). Staff asserts as well that while the Electric Infrastructure Investment and Modernization Act ("EIMA") does allow an investment return on a pension asset recorded in FERC Account 186 to be included in rates, that is specifically authorized in EIMA and does not apply to Peoples Gas.

Staff notes that the Companies argue that the more cash Peoples Gas or North Shore contributes into the trust, the lower the pension costs that Peoples Gas or North Shore has to record and ultimately recover from customers through rates. Staff responds that this argument fails to acknowledge that the Companies will receive the full amount of actuarially determined pension expense in the revenue requirement. In other words, Staff's proposed adjustments do not disallow the costs for the annual pension expense. However, Peoples Gas states that it made no contributions into the qualified pension plan during 2013 and 2014 and the Companies updated actuarial reports reflect zero employer contributions for the year 2015 for both Companies. Staff explains that its adjustments, which do not affect the amount to be recovered by the Companies in operating expenses, would have no effect on future pension contributions.

The Companies state that their argument for pension asset inclusion in rate base would be consistent with the current exclusion of their OPEB liabilities from rate base ("symmetry argument"). Staff claims that the Companies' position to include pension assets in rate base has no bearing on the proper exclusion of an OPEB liability from rate base.

Staff details that OPEB liabilities represent other post-employment benefits that had not been paid out to the OPEB trust by the end of the year and for which the utility has already received recovery from rates. Rate base is properly reduced by these OPEB liabilities to recognize that such costs are already recovered from ratepayers by their inclusion as an operating expense. Staff states that it would not be reasonable to allow shareholders a return on this cost-free source of capital to the Companies. Staff argues that the Companies' symmetry argument does not take this into account and that the Commission has also rejected this argument in the past.

Staff explains that in Docket Nos. 07-0241/07-0242 (Consol.) both Peoples Gas and North Shore excluded their OPEB liabilities from rate base*, i.e.,* neither utility reduced rate base for the OPEB liabilities. Peoples Gas also had a pension asset, which the Company did not include in rate base. Peoples Gas argued for symmetrical treatment; that is, excluding both its pension asset and OPEB liability from rate base. The Commission instead found that the pension asset should be excluded from rate base and that the OPEB liabilities should be reflected as a reduction to rate base:

> The Commission agrees with the positions asserted by GCI and Staff. Their arguments are persuasive and fully supported by the evidence. Further, they have each established that the treatment we are being urged to assign to this item today, is the same the treatment that we adopted in a number of previous decisions. On all these grounds, the Commission accepts that a rate base deduction of $7,094,000 ($4,074,000 net of related deferred taxes) is required for the North Shore accrued OPEB liability and a rate base deduction of $55,653,000 ($31,570,000 net of related deferred taxes) is required for the Peoples Gas accrued OPEB liability in the determination of the Companies' rate bases. *See* GCI Ex. 2.0 at 13.
>
> Further, we note that the underlying rationale for these adjustments is that such funds are supplied by ratepayers and not by shareholders such that shareholders are not entitled to earn a return on these funds. Accordingly, the undisputed

> record showing that Peoples Gas and North Shore contributed $15,278,614 and $1,862,247, respectively, to the pension plans during the test year, does not change the treatment of the OPEB liability. Nor are we convinced that such contributions should impact shareholders, given that these funds were provided by ratepayers through the collection of utility revenues. We observe no discussion of or opposition to this particular recalculation that the Companies propose on basis of their contribution, however, it appears to the Commission that recognizing these contributions is inconsistent with, the theoretical basis that we are applying here, *i.e.*, these contributions are ratepayer-funded.
>
> The Commission finds that the Companies' OPEB liabilities will be deducted, and, for the reasons provided by Staff, Peoples Gas' contributions of $15,278,614 and North Shore's contributions of $1,862,247 to the pension plan should not be incorporated into the calculation of the rate bases.

Docket Nos. 07-0241/07-0242 (Consol.), Order at 36. Staff states that the Commission ruled in the same manner in the last two North Shore/Peoples Gas cases, Docket Nos. 11-0280/11-0281 (Consol.) and Docket Nos. 12-0511/12-0512 (Consol.):

> The Commission agrees with both Staff and GCI concerning the adjustments to rate base made to account for net retirement benefits. Staff witness Ebrey agreed with GCI witness Effron's approach which removed the Companies' respective net pension assets from rate base, but kept the OPEB liabilities in rate base. Staff and GCI's adjustments are supported by the evidence and remain consistent with the Commission's conclusions about the pension asset in the 2007 and 2009 PGL rate cases. Those decisions both concluded that the accrued OPEB liability should be reflected in rate base but that the pension balances should not be recognized in the determination of rate base.

Docket Nos. 11-0280/11-0281 (Consol.), Order at 33.

> The Commission finds that the Companies' pension assets should not be included in rate base for the reasons stated in its past Orders. The Commission concludes, however, that the OPEB liabilities should be included in rate base, to be consistent with the prior rulings on the pension assets.

Docket Nos. 12-0511/12-0512 (Consol.), Order at 90.

In surrebuttal testimony, Peoples Gas states that if its pension asset is not included in rate base, then North Shore's pension liability should not be included. Staff argues that similar to OPEB liabilities, the Companies' position to include pension assets in rate base has no bearing on the proper exclusion of a pension liability from rate base. Pension liabilities represent pension costs that have not been paid out to the pension trust by the end of the year but for which the utility has already received recovery through rates. Staff submits that rate base is properly reduced by these pension liabilities to recognize that such costs are already recovered from ratepayers by their inclusion as an operating expense. Staff surmises that it would not be reasonable to allow shareholders a return on this cost-free source of capital to the Companies.

The Companies state that the pension assets are included in their balance sheets and that they own the assets via the trusts that hold the assets. Staff argues that it is not relevant who owns the assets of the pension trust fund because ownership is not determinative of ratemaking treatment. For example, contributed plant may be owned by a utility, but a utility does not get a return on contributed plant from a customer. Staff notes that the determining question is whether the pension assets were created with funds from shareholders or ratepayers. Further, Staff states that no evidence of outside discreet shareholder funding of the pension contributions has been presented by the Companies.

Staff reiterates that a large number of Commission orders have concluded that financing a pension asset with internally generated funds does not permit a utility a rate base return on that asset. Staff argues that the Company is seeking to collect monies from ratepayers and then charge those ratepayers with a return on investment of those monies. What is relevant is that under Illinois law for ratemaking purposes a public utility may not receive a return on investment from ratepayers for ratepayer-supplied funds. *City of Alton v. Illinois Commerce Comm'n,* 19 Ill. 2d 76, 85-6, 91 (1960); *DuPage Utility Co. v. Illinois Commerce Comm'n*, 47 Ill. 2d 550, 554, 558 (1971); *Central Illinois Light Co. v. Illinois Commerce Comm'n*, 252 Ill. App. 3d 577, 583 (3rd Dist., 1993); *see also, Business and Professional People for the Public Interest v. Illinois Commerce Comm'n ("BPI II"),* 146 Ill. 2d 175, 258 (1991). Staff reasons that the Commission has consistently rejected the attempts of other Companies to receive a return on ratepayer-supplied funds and should do so again here. *See, Citizens Utility Board v. Illinois Commerce Comm'n,* 166 Ill. 2d 111, 132 (1995) (Commission is unauthorized to depart drastically from practices established in earlier orders); *Mississippi River Fuel Corp. v. Illinois Commerce Comm'n,* 1 Ill. 2d 509, 514 (1953) (long-term consistent actions by the Commission are entitled to great weight and may be equal in force to a judicial construction).

Staff recommends a disallowance of the Companies' pension asset and related ADIT from rate base.

<u>AG's Position</u>

The AG explains that the "Retirement Benefits, Net" rate base entry, as shown on the Companies' Schedule B-1, consist of two components. The first is the prepaid pension asset. The pension asset is mainly the effect of contributions to the pension fund being in excess of the periodic pension cost, or pension income, accrued pursuant to Statement of Financial Accounting Standards 87.

The second component is primarily the accrued liability for future post-retirement OPEB, mainly health care costs. Pursuant to Statement of Financial Accounting Standards 106, the Companies must accrue for the payment of future post-retirement benefits other than pensions. To the extent that the accruals are greater than the actual cash disbursements, accrued liabilities will be reflected on the Companies balance sheets. The AG states that PGL and NS offset the accrued liability for OPEB against prepaid pensions in the calculation of the "Retirement Benefits, Net" that they include in their rate bases.

The AG maintains that in the Companies' recent rate cases, how to treat these benefits has been an issue. In Docket Nos. 07-0241 and 07-0242, the Companies did not take account of the accrued pension and OPEB balances in the determination of rate base. In response to testimony by Staff and intervenors proposing to deduct the accrued OPEB liabilities from rate base, the Companies responded that if the accrued OPEB liabilities are deducted from rate base, then the prepaid or accrued pension balances should also be recognized.

In Docket Nos. 09-0166, 09-0167, 11-0280, 11-0281, 12-0511, and 12-0512, the Companies offset the accrued liability for OPEB against prepaid pensions in the calculation of the "Retirement Benefits, Net" included in their rate bases. The AG argues that this was, in substance, the same treatment that the Companies are presenting in the current cases. The AG states that in all of these cases, the Commission found that the accrued OPEB liability should be deducted from rate base but that the pension balances should not be recognized in the determination of rate base.

Consistent with the Commission's findings in all recent cases, AG witness Effron eliminated the pension balances from rate base, but treated the accrued liability for post-retirement benefits other than pensions as rate base deductions. He also eliminated the accumulated deferred income taxes related to the prepaid or accrued pensions. The net effect of this adjustment, updated in Mr. Effron's Rebuttal testimony to reflect updates addressed in the Companies' Rebuttal testimony, are based on the average 2015 balances. The AG states that the effect of these adjustments is to reduce PGL "Retirement Benefits, Net" by $17,350,000 and related accumulated deferred income taxes by $6,881,000, resulting in a net reduction to the PGL rate base of $10,469,000. With regard to NS, the effect of Mr. Effron's proposed adjustment is to reduce the "Retirement Benefits, Net" by $8,000 and to reduce the related accumulated deferred income taxes by $5,000, which results in a net reduction to the NS rate base of $3,000. The AG submits that these adjustments should be adopted by the Commission.

<u>CCI's Position</u>

CCI recommends that the Commission adopt the adjustment proposed by both Staff witness Hathhorn and AG witness Effron to properly account for pension assets, which are ratepayer-funded. Mr. Effron's "Retirement Benefits, Net" was identical to Ms. Hathhorn's "Pension Asset Adjustments," and both are in line with the Commission's prior holdings. *See e.g.* Docket Nos. 12-0511/12-0512 (Consol.), Order at 90, Docket Nos. 11-0280/11-0281 (Consol.) Order at 33, Docket Nos. 09-0166/09-0167 (Consol.) Order at 36. CCI reasons that consistent with the Commission's previous orders, in the absence of evidence dictating a different result, the Commission should exclude the Companies' pension assets from rate base.

Commission Analysis and Conclusion

Consistent with past Commission decisions, the Commission maintains that accrued OPEB liability should be deducted from rate base but that pension balances should not be recognized in the determination of rate base. The Commission agrees with Staff and the AG and finds that Peoples Gas' pension asset should be excluded from rate base for the reasons stated in its past Orders. Further, the Commission agrees with North Shore and the AG and finds that North Shore's pension liability should also be excluded from rate base as it was in the 2007 and 2009 rate cases.

V. OPERATING EXPENSES

A. Overview/Summary/Totals

North Shore states that its final properly calculated base rate operating expenses (per its rebuttal testimony) are $74,635,000, including income taxes and reflecting the Staff and intervenor adjustments that it adopted or accepted in whole or in part in order to narrow the issues and certain updates. Peoples Gas states that its final properly calculated base rate operating expenses (per its rebuttal testimony as slightly revised in surrebuttal) are $570,562,000, including income taxes and reflecting the Staff and intervenor adjustments that it adopted or accepted in whole or in part in order to narrow the issues and certain updates.

Staff recommends total operating expenses before income taxes of $67,000,000 for North Shore and $506,894,000 for Peoples Gas.

B. Potentially Uncontested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Other Revenues

In rebuttal and surrebuttal testimony, the Companies updated the proposed other revenues figures. These figures are not contested. Therefore, the Commission approves the Companies' updated figures for these revenue amounts, subject to any derivative impacts, if any.

2. Resolved Items

a. Incentive Compensation

The Companies have three different incentive compensation plans: (i) an Executive Incentive Compensation Plan; (ii) an Omnibus Incentive Compensation Plan, consisting of various stock plans; and (iii) a Non-Executive Incentive Compensation Plan. The Companies submitted evidence of the benefits provided to customers by their incentive compensation plans, in particular metrics contained within their Non-Executive Incentive Compensation Plan and the operational metrics contained within their Executive Incentive Compensation Plan. No party has opposed the recovery of the costs related to the Companies' Non-Executive Incentive Compensation Plans. This issue is not in dispute. The Commission approves the recovery of the Companies' expenses for their Non-Executive Incentive Compensation Plans.

Only for the purposes of narrowing the issues in this proceeding and without waiving any rights to contest such amounts in future proceedings, the Companies do not object to an adjustment removing their Omnibus Incentive Compensation Plan expenses from the test year operating expenses, consistent with the recommendations made by Staff, the AG, and CCI. This issue is not in dispute. The Commission approves an adjustment removing the costs of the Omnibus Incentive Compensation Plan expenses ($1,455,000 for Peoples Gas and $245,000 for North Shore) from the Companies' test year operating expenses.

With respect to the Executive Incentive Compensation Plan, only for the purposes of narrowing the issues in this proceeding and without waiving any rights to contest such amounts in future proceedings, both the Companies and CCI have agreed not to contest proposed disallowances to portions of the Companies' Executive Incentive Compensation Plan expenses as calculated by Staff. This disallowance is consistent with the adjustment proposed by the AG. This issue is not in dispute. The Commission approves an adjustment removing $4,216,000 for Peoples Gas' and $655,000 for North Shore's Executive Incentive Compensation Plan operating expenses.

b. Executive Perquisites

Only for the purposes of narrowing the issues in this proceeding and without waiving any rights to contest such amounts in future proceedings, the Companies do not object to an adjustment removing the amounts forecasted for executive perquisites included in test year operating expenses, but only for the amounts forecasted for these items in the 2015 test year – $44,000 for Peoples Gas and $7,000 for North Shore. This is not contested. The Commission approves an adjustment removing these amounts from the Companies' respective operating expenses.

c. Interest

(i) Budget Payment Plan

In rebuttal testimony, the Companies accepted Staff's adjustments of interest expense on budget payment plans based on the December 18, 2013, Commission ruling setting the 2014 rate of interest to be paid at 0%. This subject is uncontested. The Commission approves Staff's adjustments.

(ii) Customer Deposits

In rebuttal testimony, the Companies accepted Staff's adjustments of interest expense on customer deposits based on the December 18, 2013, Commission ruling setting the 2014 rate of interest to be paid at 0%. This subject is uncontested. The Commission approves Staff's adjustments.

(iii) Synchronization (including derivative adjustments)

In rebuttal testimony, the Companies accepted Staff's adjustments to interest synchronization. This subject is uncontested. The Commission approves Staff's adjustments.

d. Lobbying

In rebuttal testimony, the Companies accepted Staff's adjustments to disallow certain inadvertently included lobbying-related expenses. This subject is uncontested. The Commission approves Staff's adjustments.

e. Fines and Penalties

In rebuttal testimony, the Companies accepted Staff's adjustments to remove fines and penalties expenses. This subject is uncontested. The Commission approves Staff's adjustments.

f. Plastic Pipefitting Remediation Project (PGL)

In rebuttal testimony, the Companies accepted Staff's adjustment to disallow inadvertently included costs associated with the Plastic Pipefitting Remediation Project. This subject is uncontested. The Commission approves Staff's adjustments.

3. Other Production (PGL)

The Companies' proposed Other Production expense for Peoples Gas is not contested. The Commission approves the Companies' Other Production expense.

4. Storage (PGL)

The Companies' proposed Storage expense for Peoples Gas is not contested. The Commission approves the Companies' Storage expense.

5. Transmission

The Companies' proposed Transmission expense is not contested. The Commission approves the Companies' Transmission expense.

6. Distribution

The Companies' proposed Distribution expense is not contested. For Peoples Gas, this includes the three-year amortization recovery of costs associated with the Section 8-102 of the Act two-phase AMRP investigation as ordered in Docket Nos. 12-0511/12-0512 (Consol.). This subject is uncontested. The Commission approves the Companies' Distribution expense.

7. Customer Accounts – Uncollectibles

The Companies proposed that the net write-off method be used. Additionally, the Companies proposed that the bad debt expense at present rates as adjusted would be the average of the actual write-offs for calendar years 2010-2012, which was $22,648,000 for Peoples Gas and $1,105,000 for North Shore (and addressed the allocation of recovery between base rates and Rider UEA-GC, Uncollectible Expense Adjustment – Gas Costs). Staff agreed that its previously proposed adjustment to uncollectible expense and any resulting adjustments were not necessary and withdrew its proposed adjustment to uncollectible expense. The Commission approves the Companies' Customer Accounts – Uncollectible expense.

8. Customer Accounts – Other than Uncollectibles

The Companies' proposed Customer Accounts – Other than Uncollectible expense is not contested. The Commission approves the Companies' Customer Accounts – Other than Uncollectible expense.

9. Customer Services and Information

The Companies' proposed Customer Services and Informational Services expense is not contested. The Commission approves the Companies' Customer Services and Informational Services expense.

10. Administrative & General (other than items in Section V.C.3)

The Companies' proposed Administrative and General ("A&G") expenses are not contested with the exception of items addressed in Section V.C.3 of this Order. The Commission approves the Companies' A&G expenses.

11. Depreciation Expense (including derivative impacts other than in Section IV.C.1.a)

The Companies' proposed Depreciation expenses are not contested except for the impacts of the 2014 AMRP costs discussed in Section IV.C.1.a of this Order. The Commission approves the Companies' Depreciation Expense (including derivative impacts other than in Section IV.C.1.a of this Order).

12. Amortization Expense (including derivative impacts)

The Companies' proposed Amortization Expense is not contested. The Commission approves the Companies' Amortization Expense (including derivative impacts).

13. Rate Case Expense (other than amortization period in Section V.C.4)

Section 9-229 of the PUA provides:

> Consideration of attorney and expert compensation as an expense. The Commission shall specifically assess the justness and reasonableness of any amount expended by a public utility to compensate attorneys or technical experts to prepare and litigate a general rate case filing. This issue shall be expressly addressed in the Commission's final order.

220 ILCS 5/9-229. The Appellate Court in Illinois-American Water held that Section 9-229 requires the Commission to "'expressly address' the basis for its findings" – *i.e.*, include "explanation or discussion" – as to the justness and reasonableness of a public utility's rate case expenses in its final order. *Illinois-American Water*, 2011 IL App (1st) 101776 at ¶¶ 47-48. Based on the guidance provided by the court in Illinois-American Water, as confirmed by the ComEd decision, the Commission has stated that a public utility must provide detailed information concerning what actual expenses have been or will be incurred, by whom, for what purpose and why such expenses were necessary in order for the Commission to make an informed determination regarding the justness and

reasonableness of recovering rate case expenses from customers. *See Docket Nos. 12-0511/12-0512* (Consol.), Order at 174; *In re Charmar Water Co*., *et al*., Docket Nos. 11-0561 – 11-0566 (Consol.), Order at 19 (May 22, 2012); *In re Charmar Water Co.*, *et al*., Docket Nos. 11-0561 – 11-0566 (Consol.), Order on Rehearing at 14 (Nov. 28, 2012).

North Shore and Peoples Gas take the position that the evidentiary record contains substantial evidence demonstrating that their revised proposed rate case expenses for this rate case – $1.947 million for North Shore and $2.945 million for Peoples Gas – are just and reasonable. NS-PGL Ex. 21.0 at 14-15; NS-PGL Exs. 21.3N, 21.3P; NS-PGL Ex. 36.0 at 13; NS-PGL Exs. 36.4N and 36.4P; Staff Ex. 7.0 at 16 and Scheds. 7.06N, 7.06P. The Utilities assert that the record evidence is more than sufficient for the Commission to specifically assess the justness and reasonableness of those expenses as required by Section 9-229 of the Act, 220 ILCS 5/9-229. Staff agrees with the Companies on the total amount of rate case costs introduced into the record to support the recovery of their rate case expenses and that the amounts sought by the Utilities were just and reasonable. This issue is uncontested.

The Commission finds that for each of the attorneys and technical experts for which recovery of rate case expense is sought, the Utilities provided detailed information concerning the nature and scope of their engagement, their hourly rates, what services they performed in support of the rate case, why those services were necessary, and what their actual expenses have been or will be incurred. Detailed invoices were provided that identified who was performing the work, what work or tasks were performed, when and for how long, and the fees and costs associated with that work. Further, the record evidence demonstrates that the rates negotiated with the attorneys and experts were reasonable in light of their experience working on rate cases generally and for the Utilities specifically, the market rate for such services, discounts and other cost protections such as “not-to-exceed” provisions provided, and the necessity and level of difficulty of the work to be performed. The record evidence also established that the Utilities review the invoices and have other safeguards in place to ensure that there is no “double-counting” for the costs of work performed by Integrys Business Services (“IBS”) personnel and that the time spent performing work by outside counsel and experts is reasonable and not duplicative. Moreover, while not determinative of the issue, the Commission notes that no party opposed recovery of the final revised amounts of rate case expenses sought by the Utilities, and that Staff testified it had reviewed the record evidence and found the amounts requested to be just and reasonable based on the facts and circumstances of this rate case.

Additionally, the Commission finds that the evidence in the record supports the conclusion that the amounts of rate case expenses not actually shown to have been expended by the time of the hearing are reasonably likely to be expended by the end of the rate case.

Further, the Commission approves the recovery of $521,000 for North Shore and $786,000 for Peoples Gas for their approved but unrecovered prior rate case expenses from their 2009 and 2011 rate case rehearings and their 2012 rate cases, as well as $118,000 for North Shore and $180,000 for Peoples Gas for their appeal costs from their 2012 rate cases.

The total rate case costs are detailed in NS-PGL Exs. 36.4N and 36.4P and are uncontested. However, the time period over which these rate case expenses will be amortized is contested. The Utilities request that these expenses be amortized over two years for ratemaking purposes. Staff proposes instead that the amortization period be changed to 2.5 years based on the proposed Reorganization pending approval in Docket No. 14-0496. This issue will be addressed below in Section V.C.4.

14. Taxes Other Than Income Taxes (including derivative impacts)

The Companies' revised proposed Taxes Other Than Income expense is not contested. The Commission approves the Companies' Taxes Other Than Income expense.

15. Income Taxes (including derivative impacts)

In rebuttal (North Shore) and surrebuttal (Peoples Gas) testimony, the Companies' revised the proposed Income Taxes expense. These expenses are uncontested except for derivative impacts of contested items. The Commission approves the Companies' Income Taxes expenses.

16. Reclassification of Costs to Plant in Service (PGL)

The Companies acknowledged in response to a Staff data request that they inadvertently omitted in Peoples Gas' rebuttal revenue requirement an adjustment to reclassify certain costs from O&M expense to Plant in Service. In surrebuttal testimony, the Companies' corrected this omission to show the reduction to O&M expense offset by derivative depreciation expense and income taxes on Plant in Service. This corrected Reclassification of Costs to Plant in Service is not contested. The Commission approves the Companies' Reclassification of Costs to Plant in Service.

17. Gross Revenue Conversion Factor

The Companies' Gross Revenue Conversion Factors ("GRCFs") are not contested. The Commission approves the Companies' GRCFs.

18. Other

As ordered by the *Docket Nos. 12-0511/12-0512 Order on Rehearing*, the Companies provided a status report in testimony at each stage of the rate case proceeding to identify any pending adjustments which required further instructions to calculate the impact of federal NOL on current and deferred income taxes. As indicated in Section IV.B.7.(b) of this Order, the Companies and Staff agreed that the stand alone federal NOLs and the related federal DTAs balances at the end of calendar year 2014 and test year 2015 are zero. Therefore, there are no pending adjustments to be identified that require further instructions to calculate the impact of federal NOLs on current and deferred income taxes.

The Companies accept Staff's adjustments to Invested Capital Tax ("ICT"), and thus there are no contested issues concerning the calculation of ICT. The Commission approves the final invested capital tax figures (including derivative impacts) based on the revenue requirement findings in the final Order.

There are no other issues related to operating expenses that are required to be discussed here.

C. Potentially Contested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Test Year Employee Levels

a. Peoples Gas

Peoples Gas' Position

Peoples Gas argues that its forecasted 2015 test year employee level should be approved but notes that the AG proposes an adjustment to this level based on the AG's assertion that the number of employees has been relatively steady through 2012 and 2013 and there is no discernible upward trend in the number of employees. The AG proposes a reduction to 1,319 full time equivalent ("FTE") employees, which would reduce the forecasted test year operation and maintenance expense by $1,904,000 and related payroll taxes by $129,000. Peoples Gas argues that the AG's adjustment is unsupported and should be rejected.

Peoples Gas forecasted an increase in its headcount from 1,306 FTE employees at the end of 2013 to 1,356 employees at the end of 2014 and throughout the entire 2015 test year. According to Peoples Gas, this forecast was based on an increased need for employees to address stricter standards of compliance with pipeline safety rules as well as increased work on AMRP. Peoples Gas states that although the AG's witness Mr. Effron admitted that he does not dispute that Peoples Gas will be hiring new employees from time to time he argued that the AG's significant adjustment is justified by the supposition that other employees will be simultaneously retiring or leaving for other reasons.

Peoples Gas contends that it has provided ample evidence to justify its increased test year employee levels – for example, Peoples Gas noted that a number of positions related to pipeline safety compliance and AMRP work have been recently filled. Additional detail regarding these positions, including identification of the pool of workers from which the positions are filled, was provided in the Companies' rebuttal testimony. Peoples Gas also identified thirty-three positions for which interviews were currently being conducted. In surrebuttal testimony, the Companies noted that approximately twenty positions will be filled by Utility Workers who graduated from the Power for America training program at Dawson Technical Institute in Chicago in September 2014. Peoples Gas states that it has created a well-founded expectation that members of the Power for America training program will be hired for permanent employment.

Peoples Gas counters that the AG allegations that Peoples Gas failed to indicate that students in the program had actually already started are unfounded and demonstrate a misunderstanding of the Dawson Technical Institute training program. Peoples Gas explains that graduating students are hired for a six-week internship program through the company with the goal of full time employment following the conclusion of the internship. Peoples Gas states that the AG's criticism is misplaced because Peoples Gas rightfully did not want to provide a premature update at the time of the hearings. Peoples Gas argues that the AG's adjustment does not take into account the recent additions to the Peoples Gas workforce, nor does it acknowledge the positions that are currently being filled. As explained by the Companies' witness Mr. Lazzaro, these Utility Workers participate in a six-week long internship through Peoples Gas, wherein the workers are assigned to a district shop and are evaluated by management staff, supervisors, and peers. As noted by Mr. Lazzaro, Peoples Gas seeks to hire those individuals who successfully complete the internship program as full-time utility workers.

Peoples Gas states that during the evidentiary hearings held on September 23, 2014, the AG entered certain cross-exhibits into the record reflecting Peoples Gas' actual employee levels as of December 2013 and July 2014. In doing so, the AG noted that the actual total FTE employee count as of December 2013 was 1,299.5, while the actual total FTE employee count as of July 2014 was 1,314.6. Although the AG correctly identified the actual employee levels for Peoples Gas in July 2014, the Companies emphasize that the AG's adjustment does not take into account Peoples Gas' planned hiring activities – in particular, the probable hiring of approximately 20 of the utility workers graduating from the Dawson Technical Institute training program, as identified and discussed in surrebuttal and in cross-examination. Peoples Gas asserts that it has clearly identified planned hiring practices in the near future, including the probable number of qualified and trained FTE employees.

Peoples Gas states that during the evidentiary hearings in this proceeding, the AG also introduced a discovery response related to certain proposed FTE employee commitments proposed in the WEC-Integrys transaction docket, Docket No. 14-0496. This discovery response indicated that testimony filed in the separate WEC-Integrys transaction docket, by a witness that has not appeared in the instant proceeding, committed to maintaining an overall minimum number of FTE employee positions in Illinois for two years after the closing of the transaction, showing 1,294 FTE employee positions through Peoples Gas within that minimum. This discovery response was additionally relied upon by CCI in its Initial Brief. The Companies argue that this information does not support the AG's nor CCI's proposed adjustments to headcount levels. As an initial matter, the WEC-Integrys transaction is subject to approval by the Commission and several other state and federal governmental agencies, and, if approved, it is not expected to close until Summer 2015. As such, the proposed commitment is subject to the proposed transaction, which has not yet been approved. In addition, the proposed commitment identifies a minimum number of FTE employee positions, but the response itself makes clear that the proposed commitment is for 1,953 FTE employees in Illinois, and not for the breakdown shown among Peoples Gas, North Shore, and IBS. The Companies emphasize that this point was acknowledged by the AG. The information from the WEC-Integrys transaction docket simply reflects a proposed commitment to maintain at least 1,953 FTE employees in Illinois – it does not preclude Peoples Gas from maintaining the forecasted 1,356 employees, for which Peoples Gas has identified a need. Moreover, the public announcements and data request responses do not indicate that employment levels would be decreased although potential reductions may occur due to natural attrition. The Companies argue that the Commission should reject this discovery response as not probative as to the proceeding at hand.

Peoples Gas states that although CCI did not address this issue in the rebuttal testimony of its witness, Mr. Gorman, CCI's Initial Brief reiterates the position expressed by the CCI witness in direct testimony. Like the AG, CCI relies upon Peoples Gas' historical employee levels, arguing that Peoples Gas' employee levels be reduced to match the Company's May 2014 actual levels. In addition, CCI also wholly disregards the evidence related to Peoples Gas' current and planned hiring practices.

Peoples Gas indicates that Staff agrees with Peoples Gas' forecasted employee levels, and notes that the adjustment proposed by the AG and CCI do not take into account Peoples Gas' recent and planned hiring. Peoples Gas concludes that the Commission should reject the adjustments proposed by the AG and CCI, and should adopt Peoples Gas' test year employee level.

Staff's Position

Staff submits that the Commission should reject AG witness Effron's and CCI witness Gorman's proposals to reduce the number of projected test-year employees based on analyses of historical trends. Staff maintains that while their analyses are logical to some extent, their arguments do not consider the Companies' recent hiring and do not refute the Companies' testimony regarding planned additional hiring.

AG's Position

Peoples Gas is forecasting 1,356 FTE employees for the 2015 test year. The AG states that despite this lofty goal, PGL's average level of FTE employees was around 1,302 in the first five months of 2014. This level is below the average actual FTE employment level of 1309.6 from the last six months of 2013. Additionally, the actual number of FTE employees in April and May of 2014, 1,298.5, was slightly lower than the average FTE employees in the first three months of 2014, 1,305.5. The AG states that the PGL employment level rose from May to July of this year, but only to 1,314.6. Moreover, as PGL witness Lazzaro confirmed in cross-examination, in each and every month from January through July of 2014, the actual FTE employment level was below the authorized level.

The AG asserts that in light of these trends, it is difficult to find credible the Company's forecast that it will actually fill its authorized employment level of 1,356 FTE employees by the end of 2014. Mr. Effron thus proposed in rebuttal testimony that PGL's test-year FTE employee level should be reduced to 1,319, the average for June and July of 2014. Mr. Effron's proposal would reduce PGL's test-year operation and maintenance expense by $1.904 million and related payroll taxes by $129,000.

The AG notes that in rebuttal testimony filed August 4, 2014, PGL witness Mr. Lazzaro stated, identically to Mr. Kinzle's rebuttal statement, that PGL's employee count at any moment is only a snap shot in time that does not reflect existing and future additions to employee count. Mr. Lazzaro then stated that Peoples has taken measures toward filling 33 open positions, bringing actual headcount up to forecasted test-year headcount and rendering Mr. Effron's proposed adjustment moot. The AG states that Mr. Lazzaro cited, for example, twenty utility workers from Dawson Technical Institute who will begin internships with the Company in September 2014. In cross-examination, though, Mr. Lazzaro admitted that the internship is merely a six-week evaluation by management and peers; permanent employment is not guaranteed. The AG continues that at no point during his surrebuttal testimony (filed September 12) or his cross-examination and re-direct examination (September 23) did Mr. Lazzaro indicate that the 20 Dawson Technical Institute students who purportedly would be starting work during September 2014 had actually already started.

The AG states that Mr. Lazzaro also referred in his rebuttal testimony to seven technician openings and nine supervisor openings (including three openings that will arise soon due to pending retirements) for which interviews are allegedly in process. The AG argues that given PGL's track record of not filling authorized employment levels the Commission should give a second or third thought to simply taking the Company's word that it will fill these openings. Moreover, even if the Company did fill the openings, attrition is also a significant consideration at Peoples Gas, as it is at North Shore. The Company hired 21 utility workers from Dawson Technical Institute in April 2014, but the number of Peoples Gas FTE employees decreased from 1,304.5 at the end of March 2014 to 1,298.5 employees at the end of April 2014 and then to 1,296.5 at the end of May 2014. Mr. Lazzaro admitted during cross-examination that attrition at the Company is generally positive. He also admitted that eight employees left the Company during July of 2014 due to some retirements and possibly a termination. The AG maintains that it is clear that the Company has to constantly hire more than attrition just to keep employment levels from falling. The AG continues that even if the Company had proven that it will hire enough new employees to fill currently authorized openings (which it has not), it must also show that it will additionally hire enough to keep up with attrition.

The AG concludes that in light of Peoples Gas' poor track record of filling authorized employment levels, Mr. Lazzaro failed to show with credible evidence that Peoples Gas will make new hiring net of attrition that will bring Peoples' 2015 test-year employment up to 1,356. The AG believes that the Commission should adopt Mr. Effron's downward adjustment.

<u>CCI's Position</u>

CCI submits that even though the utility forecasts an increased level of employees, PGL has seen a decline in its actual number of employees. For the period February 2014 to May 2014 the actual number of employees declined by 10. Furthermore, PGL actually has 60 fewer employees as of May 2014 (1,296) than it forecasted for May 2014 (1,356). PGL forecasts that it will employ 1,356 employees in the 2015 test year. CCI notes, however, that the record shows that during the historical period July 2013 through July 2014, PGL has never achieved its forecasted/authorized level of employees (1,356 employees) in any month of that period.

CCI states that PGL's actual employee levels have shown a decline (rather than the forecasted increase), they have persistently been less than forecasted by the PGL, and the Companies' projected merged staffing levels (for reorganization case commitments) are less than forecasted by PGL for setting rates. CCI proposes that the employee levels forecasted for the 2015 test year be reduced by 60 employees. That adjustment represents the difference between the actual May 2014 full-time employee levels and the full-time employee level PGL previously forecasted for the 2015 test year.

CCI argues that its proposed test year employee level of 1,296 employees actually exceeds (by two) the number of PGL employees the Companies have suggested will be kept in Illinois if their proposed reorganization (in Docket 14-0496) is closed. CCI asserts that this adjustment will reduce the PGL 2015 test year operating and maintenance payroll expense by $4 million.

Commission Analysis and Conclusion

The Commission agrees with Peoples Gas and Staff and approves Peoples Gas' forecasted 2015 employee levels. Peoples Gas offered detailed evidence regarding its current and planned hiring practices, and identified specific positions that are due to be filled. The Commission finds that the adjustments to Peoples Gas' forecasted 2015 FTE employee levels, as made by the AG and CCI, are unwarranted.

b. North Shore

North Shore's Position

North Shore contends that its forecasted 2015 test year employee level should be approved. North Shore notes that the AG proposes an adjustment to North Shore's forecasted 2015 test year employee level based on its assertion that the number of North Shore employees has been relatively steady through 2012 and 2013 and there is no discernible upward trend in the number of employees. The AG proposes that North Shore's 2015 test year payroll expense be reduced to reflect a January 2014 through May 2014 average employee count of 166 FTE employees, which would reduce the forecasted test-year operation and maintenance expense by $670,000 and related payroll taxes by $48,000. North Shore argues that the AG's adjustment is unsupported and should be rejected.

North Shore forecasted an increase in its headcount to 178 FTE employees throughout 2014 and 2015. In support of this forecast, North Shore noted that the proposed adjustments to the test year employee headcount do not take into account existing and future additions to employee count. North Shore provided evidence demonstrating that interviews were being conducted to fill thirteen open positions, and that an additional two positions were anticipated to be filled in the fourth quarter of 2014. In addition, North Shore noted that the increased employee levels are necessary and reasonable, as the company's current employee levels has forced it to operate at levels below the budgeted headcount, resulting in an inefficient reliance on overtime and contractors to supplement its workforce.

During the evidentiary hearings held on September 22, 2014, the AG entered certain cross-exhibits into the record reflecting North Shore's actual employee levels as of December 2013 and July 2014. In doing so, the AG noted that the actual total FTE employee count as of December 2013 was 164.7, while the actual total FTE employee count as of July 2014 had decreased to 163.68. Although the AG correctly identified the actual FTE employee count for North Shore, North Shore argues that these numbers do not take into account North Shore's expressed planned hiring goals for 2014. North Shore emphasizes that it is currently interviewing candidates for 13 open positions, four of which are for internal company construction inspector positions. North Shore states that it has clearly identified a need for additional FTE employees in specific positions that fill core functions of the utility.

North Shore notes that during the evidentiary hearings in this proceeding the AG also introduced a discovery response related to certain proposed FTE employee commitments proposed in the WEC-Integrys transaction docket, Docket No. 14-0496. As discussed with respect to Peoples Gas, this discovery response identifies a proposed commitment that is subject to approval of the WEC-Integrys proposed transaction. Moreover, the AG acknowledged that the proposed commitment as stated in the discovery response identifies a commitment for 1,953 FTE employees in Illinois, not for the breakdown among Peoples Gas, North Shore, and IBS. The AG further admits that the North Shore commitment is for a minimum of 166 FTE employees, which equals the number of employees forecasted by the AG. However, North Shore argues that the AG attempts to explain this fact away by arguing that the company-based employee figures must be based on some carefully calculated expectation for the test year. North Shore asserts that the AG introduced this data request, as issued in a separate docket by a witness that is not participating in the instant proceeding, and then attempts to explain away the numbers by assuming that there is some unknown, unidentified calculation that assumes that North Shore will not hire nor maintain additional employees to meet its forecasted 2015 test year FTE employee count. North Shore argues that the AG does not, and cannot, provide any evidence to rebut North Shore's prudent and reasonable 2015 forecasted employee levels, and that the Commission should reject the AG's adjustment.

North Shore adds that although CCI did not address this issue in the rebuttal testimony of its witness, Mr. Gorman, CCI's Initial Brief reiterates the position expressed by the CCI witness in direct testimony. The Companies state that, like the AG, CCI relies upon North Shore's historical employee levels, and wholly disregards the evidence related to North Shore's current and planned hiring practices.

Finally, North Shore notes that Staff agrees with North Shore's forecasted employee levels, and maintains that the adjustment proposed by the AG and CCI do not take into account North Shore's recent and planned hiring.

North Shore concludes that the Commission should reject the adjustments proposed by the AG and CCI, and should adopt North Shore's test year employee level.

<u>Staff's Position</u>

Staff argues that the Commission should reject AG witness Effron's and CCI witness Gorman's proposals to reduce the number of projected test-year employees based on analyses of historical trends. According to Staff, while their analyses are logical to some extent, their arguments do not consider the Companies' recent hiring and do not refute the Companies' testimony regarding planned additional hiring.

<u>AG's Position</u>

North Shore Gas is forecasting 178 FTE employees for the 2015 test year. The AG states that North Shore indicated in a discovery response and confirmed during the cross-examination of Mr. Kinzle that the Company's actual FTE employee level as of the end of December, 2013 was 164.7. As Mr. Effron noted in direct testimony, North Shore's actual FTE employees was stable at around 166 in the first five months of 2014. He further observed that the number of employees has been relatively steady through 2012 and 2013 and there is no discernible upward trend in the number of employees. Mr. Effron proposed reducing North Shore's test-year FTE employee level to 166.

In rebuttal, Mr. Effron noted that his proposed test-year level of 166 is actually higher than the actual number of North Shore FTE employees in June and July of 2014 – 163.68. The June and July 2014 actual FTE employment level at North Shore actually declined from levels prevalent at the end of 2013 and in early 2014. Mr. Effron's recommendation for the 2015 test-year employment level is "conservative" in favor of the Company. The AG states that Mr. Effron's proposal would reduce North Shore's test-year operation and maintenance expense by $670,000 and related payroll taxes by $48,000.

In rebuttal testimony filed August 4, 2014, North Shore witness Mr. Kinzle argued that North Shore's employee count is only a snap shot in time that does not reflect existing and future additions to employee count. He further stated that North Shore intends to hire additional employees in 2014, including thirteen in September and two more in the fourth quarter, which (after the departure of one summer intern), would theoretically bring North Shore's FTE employee count to 178 by year-end 2014. The AG states, however, that Mr. Kinzle admitted during cross-examination that, despite filing surrebuttal testimony in September of this year, he did not provide any update on the status of those purported thirteen new hires. Mr. Kinzle also admitted that historically, the Company's employee attrition is positive, and the net effect of new hires versus attrition is zero, which implies that any new hires that are actually effected in the latter part of 2014 may very well be balanced by an equal amount of employee departures. The AG adds that the Company also had an opportunity to provide a further update on the status of the purported thirteen new hires during re-direct examination, but declined to do so.

The AG finds that in light of North Shore's poor track record of filling authorized employment levels, Mr. Kinzle failed to show with credible evidence that North Shore will make new hiring net of attrition that will bring the Company's 2015 test-year employment up to 178. The AG states that the Commission should adopt Mr. Effron's downward adjustment.

The AG adds that in Docket No. 14-0496, the ICC proceeding for the merger application of Integrys and WEC, the Joint Applicants stated in a discovery response that they commit to preserve employment level in Illinois of 1,953 FTE employees for two years after the proposed July 2015 merger closing. The AG explains that the discovery response states that the commitment of 1,953 FTE employees is in the aggregate, and not for each company, but the company-based employment figures used to construct the aggregate commitment are telling, as they must be based on some carefully calculated expectation for the test year. The North Shore figure is equal to Mr. Effron's recommendation for the test year. Also, the Peoples figure in the Docket No. 14-0496 discovery response is below Mr. Effron's recommendation for the test year in this proceeding. According to the AG, these figures provide an additional reason for the

Commission to adopt Mr. Effron's downward adjustment to the Companies' forecasted test-year employment levels.

Furthermore, the AG submits that while Staff witness Kahle stated in his rebuttal testimony that he opposes Mr. Effron's proposal to reduce test-year employee levels because the proposal does not take into account planned additional hiring and recent additional hiring, he admitted that his only bases for this position were Mr. Lazzaro's testimony about PGL's plans for 21 additional hires before the end of this year and a discovery response not in the record. The AG argues that accepting the Companies' claims about future actions at face value is simply not a reasonable basis for agreeing with their positions.

The AG claims that Mr. Kahle had access to extensive data when he formulated his recommendations on this topic. He admitted that North Shore's actual FTE employment at the end of July 2014 was below the level at the end of December 2013 and that for each and every month of January through July, 2014, the actual FTE employment level was below the authorized level. Mr. Kahle also confirmed Peoples' actual FTE employment levels were under authorized FTE employment levels for each and every month from July 2013 through July 2014. Mr. Kahle then admitted that, while he was aware of these discrepancies at the time he formulated his rebuttal testimony, he merely considered current employee levels and the companies' plan, and did not project any history of actual budget differences in formulating his position. The AG maintains that in light of Mr. Kahle's failure to carefully analyze the credibility of the Companies' claims using available evidence, the Commission should not accept his recommendation.

The AG concludes that the Commission should adopt AG witness Effron's proposed adjustments to the test-year FTE employment levels of North Shore Gas from the Company's forecast of 178 down to a more reasonable level of 166.

CCI's Position

CCI claims that NS has seen a decline in its actual number of employees for the period August 2012 to May 2014 and adds that NS actually had 12 fewer employees as of May 2014 (165) than it had forecasted for May 2014 (177). NS forecasts that it will employ 177 employees in the 2015 test year. However, CCI claims that the record shows that for the historical period July 2013 through July 2014, NS has never achieved its forecasted/authorized level of 170 employees (in 2013) and 177-178 employees (in 2014) in any month of that time period.

CCI argues that historically NS employee levels appear to be declining, have actually been less than forecasted by the Company, and are projected to be less than forecasted by NS following the proposed reorganization. CCI proposes that the employee levels forecasted for the 2015 test year be reduced by 12 employees which is the difference between the actual May 2014 full-time employee levels and the full-time employee levels NS previously forecasted for the 2015 test year. CCI states that its recommended employee level of 165 is actually only one employee less than the Companies have suggested will be kept in Illinois, for NS, in the event the reorganization proposed in Commission Docket 14-0496 is closed. This adjustment will reduce the NS 2015 test year operating and maintenance payroll expense by $1 million.

Commission Analysis and Conclusion

The Commission agrees with North Shore and Staff and approves North Shore's forecasted 2015 employee levels. North Shore offered detailed evidence regarding its current and planned hiring practices, and identified specific positions that are due to be filled. The Commission finds that the adjustments to North Shore's forecasted 2015 FTE employee levels, as made by the AG and CCI, are unwarranted.

2. Medical Benefits

a. Peoples Gas

Peoples Gas' Position

The Companies state that the AG fails to provide any credible basis for its attempt to reject the Companies' medical benefits costs which are properly based on an independent actuarial report. Throughout the record, the Companies have provided evidence explaining how the Companies' figures are based on an independent actuary report, and detailing the supporting calculations that were supplied to Staff and intervenors. The Companies state that independent actuarial reports have regularly been relied upon by the Commission in numerous rate cases, for many years. The Companies note that AG witness Mr. Effron argued for use of the most current actuarial study to set pension expense in *Illinois Power Co*., Docket No. 91-0147, 1992 Ill. PUC Lexis 97, 177-178 (Feb. 11, 1992). The Companies assert that Mr. Effron was successful in that case and the Commission there found arguments against use of the study "too speculative" just as it should do so here.

The Companies indicate that while Mr. Effron argued against rejection of an actuarial study in Illinois Power Co., in the current cases he and the AG argue that the independent actuary report that was used to provide the foundation of the Companies' forecasts is not enough. The Companies state that Mr. Effron has provided no credible evidence that explains why the independent actuary's figures should not be relied upon by the Commission and has not articulated any way in which the actuarial report is flawed. The Companies argue that this is critical because they are not claiming that an actuarial report can never be rejected, but rather that sufficient grounds must be presented before rejecting a traditionally accepted report that has been supported in the evidence.

The Companies continue that Mr. Effron's position rests on nothing more than his personal opinion that based on the rate of medical cost increases from 2012 to 2013, the independent actuary's estimate of how medical benefits costs will increase by 2015 must be unreasonable. The Companies argue that this is not a valid basis for rejecting the independent actuary report and reducing medical benefits costs, and merely speculation.

The Companies maintain there is no credible or relevant evidence supporting Mr. Effron's opinion, and the AG points to no independent evidence suggesting a lower rate of medical benefits costs increases. The AG has not presented any valid reason to reject the independent actuary's figures, which are based on trend information, properly reflects changes in numbers of employees, and are consistently and correctly calculated.

The Companies add that Staff also opposes the AG's proposed medical benefits adjustments and shares nearly identical sentiments with the Companies. The Companies continue that the AG had the opportunity to cross-examine Staff witness Mr. Kahle regarding the reasonableness of the Companies' proposed medical benefits figures that were based on the independent actuary's figures. However, the AG's questions essentially assumed away the independent actuary report, which makes them irrelevant and of no probative value.

AG's Position

The AG states that PGL is forecasting an increase in medical benefits costs from $9,059,000 in 2012 to $13,892,000 in 2015, an increase of 53%. AG witness Effron testified that while medical costs did increase, those amounts are nowhere near the average annual rate of increase from 2012 to 2015 projected by PGL. The AG asserts that the forecasted 2015 medical benefits costs of $13,892,000 in 2015 still represents an increase of 43% over the actual 2013 medical benefits costs. The AG claims that while it may not be unreasonable to expect some increase in medical benefits costs from 2013 to 2015, the Companies were unable to justify a forecasted increase of 43% over a two-year period is reasonable.

The AG argues that in order to recognize a normalized amount of Medical Benefits expense in the test year, Mr. Effron applied a reasonable annual escalation factor to the actual 2013 medical benefits costs to project the 2015 test-year costs. The Companies explained that they applied certain escalation rates in response to the AG's discovery. According to NS Exhibit 12.0, Page 6, North Shore escalated 2013 medical cost per FTE employee by 4.9% for 2014 and 8.0% for 2015 to determine the projected rate for 2015. In Data Request PGL AG 1.51, the Companies were asked to provide supporting documentation for the projected 8% increase from 2014 to 2015. The response was provided in a one-sheet attachment titled "2013 rate development methodology and assumptions," with three lines showing an "Annual trend" of "8.5%, 6% prescription drug, and 5% dental." The cover sheet explained that the 8% trend was a blend of the 8.5% and the 6% prescription drug escalation rates. In Mr. Effron's opinion, this is not adequate justification for an increase of 8% from 2014 to 2015. Accordingly, he recommended that a more reasonable and data-based annual escalation rate of 4.9% be applied to the actual 2013 medical benefits for two years to project the 2015 test-year medical benefits expense.

The AG explains that the effect of Mr. Effron's proposed modification to the projection of PGL 2015 test-year medical costs is to reduce test-year medical benefits costs by $3,239,000. This adjustment was modified in Rebuttal testimony to incorporate employee increases from 2013 to 2014 for Peoples Gas. A similar adjustment to IBS medical benefits charged to Peoples Gas was also made. On his Ex. 7.2, Schedule DJE PGL C-2, Mr. Effron adjusted the projected increase in Peoples Gas benefits to reflect an increase of the employee complement of 1.8% in 2014 over the employee complement in 2013. On his Ex. 7.2, Schedule DJE PGL C-3, he adjusted the projected increase in IBS medical benefits charged to Peoples Gas to reflect an increase of 1.4% above the wage rate related increase in labor charged from IBS to Peoples Gas.

The AG states that in response to these adjustments, NS/PGL witness Hans offered several criticisms of Mr. Effron's proposed adjustments, but no substantive justification for the magnitude of the increases being forecasted by the Companies. The only explanation provided is that the forecasts are based on estimates from the Companies' actuaries. The AG asserts that statement in no way explains why the Companies are forecasting an increase in medical benefits of 43% for PGL over that two year period, an increase of 52% from 2013 to 2015 for North Shore, and a 31% increase for their affiliate, IBS, over the same period. The AG continues that Ms. Hans offers no explanation of any factors or trends that could reasonably account for increases of those magnitudes. Ms. Hans describes the process for calculating medical benefits expenses but she does not explain why the excessive increases should be incorporated into the determination of test year medical benefits expenses.

The AG concludes that Mr. Effron's more reasonable forecast of Medical Benefits for the test year should be adopted by the Commission.

Commission Analysis and Conclusion

The Commission agrees with Peoples Gas and finds that it provided extensive evidence supporting approval of its medical benefits costs. The Commission has relied upon actuarial reports during rate cases in the past and absent a proven flaw in such a report, which the AG has failed to mention, the Commission will not ignore such a report. The Commission rejects the AG's proposal and adopts Peoples Gas' proposed medical benefits expense.

b. North Shore

Company's Position

The Companies state that the AG's arguments as to North Shore's medical benefits costs parallel the AG's arguments as to Peoples Gas medical benefits costs, lack any valid basis, and should be rejected for the same reasons. *See* Section V.C.2.a of this Order.

AG's Position

The AG states that like the adjustment to Medical Benefits for Peoples Gas, Mr. Effron's adjustment to North Shore's forecasted test year level is significantly and inexplicably overstated. NS is forecasting an increase in medical benefits costs from $1,329,000 in 2012 to $1,927,000 in 2015, an increase of 45%. Based on the response to DR NS AG 1.42, the medical costs actually decreased from $1,329,000 in 2012 to $1,271,000 in 2013. Thus, the forecasted 2015 medical benefits costs of $1,927,000 in 2015 represent an increase of 52% over the actual 2013 medical benefits costs. The AG asserts that while it may not be unreasonable to expect some increase in medical benefits costs from 2013 to 2015, Mr. Effron testified that he did not believe that a forecasted increase of 52% over a two-year period is reasonable.

Once again, he recommended that a reasonable escalation factor be applied to the actual 2013 medical benefits costs to project the 2015 test-year costs. North Shore's forecasted 2013 medical cost per FTE employee was escalated by 4.9% for 2014 and 8.0% for 2015 to determine the projected rate for 2015. Again, no additional supporting documentation was forthcoming from the Company in response to the aforementioned DR PGL AG 1.51. The same aforementioned one-sheet attachment titled "2013 rate development methodology and assumptions," with three lines showing an "Annual trend" of "8.5%, 6% prescription drug, and 5% dental" was provided. Again, as Mr. Effron noted, this is not adequate justification for an increase of 8% from 2014 to 2015. He therefore recommended that an annual escalation rate of 4.9% be applied to the actual 2013 medical benefits for two years to project the 2015 test-year medical benefits expense.

The AG states that the effect of Mr. Effron's proposed modification to the projection of NS 2015 test-year medical costs results in a $528,000 to 2015 test-year medical benefits costs and results in a reduction of $418,000 to medical benefits costs charged to 2015 test-year operation and maintenance expenses. In Rebuttal testimony, Mr. Effron noted that there has been no increase in the North Shore employee complement since 2013, and, therefore, no modification of his proposed adjustment to the North Shore test-year medical benefits expense is necessary. He added that even though there has been a slight increase in the number of IBS employees in 2014 over 2013, there has been no increase in the IBS labor expense allocated to North Shore in 2014. As benefits expense should follow the labor expense, Mr. Effron testified that no increase in IBS medical benefits should be charged to North Shore.

The AG maintains that the Commission should adopt AG witness Effron's more reasonable representation of forecasted Medical Benefits expense in the PGL and NS test years.

Staff's Position

Staff argues that the Commission should reject AG witness Effron's proposed adjustment to reduce the amount of projected direct medical benefit costs and medical benefits allocated from IBS based on applying an inflation factor to historical costs. Staff asserts that Mr. Effron's linear analysis does not allow for consideration of the Companies' projected increases in the number of employees or the Companies' independent study of claims.

Staff states that should the Commission determine to reduce the number of projected test-year employees, however, there should be a related reduction in projected direct medical benefit costs.

Commission Analysis and Conclusion

The Commission agrees with North Shore and finds that it provided extensive evidence supporting approval of its medical benefits costs. The Commission has relied upon actuarial reports during rate cases in the past and absent a proven flaw in such a report, which the AG has failed to mention, the Commission will not ignore such a report. The Commission rejects the AG's proposal and adopts North Shore's proposed medical benefits expense.

3. Other Administrative & General

a. Integrys Business Support Costs

(i) Labor

Companies' Position

The Companies state that their cost figures reflect properly forecasted IBS labor costs cross-charges. The Companies note that AG witness Mr. Effron's proposals to reduce the level of these costs are inconsistent and without merit. The Companies proffer that while the issue to be addressed should be whether the forecasted level of IBS labor costs to be cross-charged in 2015 is reasonable, the AG proceeded as if the true issue was determination of the level of costs or the IBS headcount as of some point in 2014.

The Companies maintain that Mr. Effron's proposals were based on his analysis of data from 2012, 2013, and the first four months of 2014. However, he used one method for Peoples Gas (his figure is based on the 2013 expense level with a wage increase level based on two years of the average wage increase level from 2012 to 2015) and a different one for North Shore (his figure is based on the 2013 expense level with a wage increase level based on one year of the average wage increase level from 2012 to 2015). He also did not take into account any other factors that impacted labors costs between 2013 and 2015.

The Companies contend that Mr. Effron's direct testimony proposal ignored the three primary reasons that these labor costs were forecasted to increase: (1) the increased services provided to the Companies and the requisite increases in IBS labor to provide those services, (2) increased FTE employees at IBS, and (3) a proper shift in the allocation percentages. The Companies note that Mr. Effron's rebuttal proposal did not correct for any of the above flaws in his direct testimony proposal. In fact, during rebuttal, the only change made by Mr. Effron was to correct for his using incorrect allocation percentages, and to calculate the Peoples Gas figure by escalating 2013 costs based on the rate of increase in the first six months of 2014.

The Companies state that the AG points to the percentage increases in cross-charged labor costs from 2012 to 2013, but the AG does not show how that is relevant. According to the Companies, the issue is 2015. The AG argues that Mr. Effron's proposal is reasonable as to North Shore on the grounds that the actual labor expense in the first four or six months of 2014 was lower than in the same period of 2013, and that it is reasonable as to Peoples Gas on the grounds that, while the actual labor expense in the first four months of 2014 was higher than in the same period of 2013, the rate of increase in those four months was less than was forecasted. Again, the Companies note that the issue is 2015.

The Companies assert that the AG's repeated reliance in cross-examination and later in briefing on data extrapolated from specific and limited periods from 2012, 2013 and 2014 simply serves to confirm certain mathematical calculations that reflect the increase in costs between specific years. The Companies note that the AG entered several cross-exhibits into the record, purportedly in support of the AG's claim that the forecasted test year amounts of labor expense charged by IBS to North Shore and

Peoples Gas is excessive and unjustified. However, the Companies contend that these cross-exhibits simply reflect cost information, and nothing more. The Companies explain that this financial information is not relevant to the forecasted 2015 costs, and does not provide any support for the AG's inconsistent and meritless proposals.

Finally, the Companies maintain that neither of the AG's arguments takes into account the three points noted above from the rebuttal of Companies' witness Ms. Kupsh regarding why the 2015 costs are forecasted to be higher. The AG's response to this subject is circular. Additionally, the AG admits that Mr. Effron's proposals did not "explicitly" address those three points, but claims that his looking at data from 2012, 2013, and the beginning of 2014 somehow implicitly took them into account. That argument assumes, without any identified factual basis, that that data fully reflects those three factors.

The Companies add that Staff opposes the AG's proposals and recommends that they not be adopted. The AG attempts to weaken Staff's testimony, but all the AG demonstrates is that Staff witness Mr. Kahle, in concluding that the 2015 forecasted level is reasonable, did not perform an "independent analysis" of whether the three factors cited by Ms. Kupsh already have resulted in increases, and did not assess whether the costs have been increasing in the recent past.

The Companies contend that, as a result of the AG's deficiencies in evidence and lack of meritorious proposals, the Companies' well-supported figures should be adopted, as both the Companies and Staff contend.

<u>Staff's Position</u>

Staff submits that the Commission should reject AG witness Effron's proposed adjustment to reduce the amount of IBS O&M cross charges for labor for both Companies. Mr. Effron's analysis increases historical costs by a general wage increase factor. The Companies demonstrate three factors that account for the additional increases: an increase in direct charges from IBS related to increased services; an increased number of employees; and a change in the allocation percentages based on the increased number of employees and total spending. Staff finds that while Mr. Effron's analysis is logical, it does not refute the Companies' testimony supporting the increases.

Staff states that should the Commission determine to reduce the number of projected test-year employees, however, there should be a related reduction to cross charges for labor for both Companies.

<u>AG's Position</u>

The AG argues that the forecasted test year amounts of labor expense charged by IBS to North Shore and Peoples Gas is excessive and unjustified. The 2015 test-year O&M expense includes $7,630,000 of labor expense charged by IBS to North Shore, an amount that AG witness Effron testified was unreasonably high and unsupported. He explained that the forecasted $7,630,000 expense represents an increase of 17% over the actual 2012 expense. NS/PGL witness Tracy Kupsch did not dispute that calculation. But based on the response to Data Request NS AG 1.51, the actual IBS cross-charged labor expense to North Shore decreased from $6,521,000 to $6,330,000 in 2013. The

AG notes that the response to Data Request NS AG 7.05 shows the cross-charged labor expense to NS in the first four months of 2014 was actually less than the expense in the corresponding period in 2013. Based on this actual experience, the projected increase in labor expense to the 2015 test year is clearly overstated and should be modified. The AG continues that AG Cross Ex. 2 shows that the IBS labor charged to North Shore was forecasted to increase by approximately 8.8 percent from 2013 to 2014.

AG witness Effron recommended that the actual 2013 expense be used as a base to project the 2015 test-year labor expense, and further that the 2014 IBS labor expense charged to North Shore be assumed to be the same as the 2013 expenses. The AG asserts that this assumption should be considered a conservative one because the expense in the first six months of 2014 was actually lower than the expense in the first four months of 2013.

The AG states that the actual labor expense in 2013 was $6,331,000. The response to Data Request NS AG 3.01 shows that the forecast of 2015 cross-charged labor expense includes the effect of $740,000 of wage rate increases from 2012 to 2015. This translates into an average increase in wage rates of 3.78% per year. Application of this increase to the assumed 2014 labor expense of $6,331,000 results in a projected 2015 labor expense of $6,570,000. This is $1,060,000 less than the $7,630,000 of labor expense forecasted by NS. The AG believes that the NS test-year operation and maintenance expense should be adjusted accordingly.

For Peoples Gas, the forecasted PGL 2015 test-year O&M includes $45,781,000 of labor expense charged by IBS. The AG states that this forecasted labor expense amount, too, is unreasonable. Mr. Effron explained that the forecasted $45,781,000 expense represents an increase of 21% over the actual 2012 expense, a number NS/PGL did not dispute. But based on the response to DR PGL AG 1.59, the actual IBS cross-charged labor expense to PGL increased by only 0.5% from 2012 to 2013, well below the rate of increase forecasted by PGL. The AG states that the response to DR PGL AG 7.07 shows an increase in the cross-charged labor expense to PGL in the first four months of 2014 over the corresponding period in 2013, but at a lower rate than the increase forecasted by PGL from the actual 2013 labor expenses to 2014. The AG argues that based on this actual experience, the projected increase in labor expense to the 2015 test year is overstated and should be modified.

Mr. Effron testified that the actual 2013 expense be used as a base to project the 2015 test-year labor expense charged to Peoples, similar to his adjustment for North Shore. The actual labor expense in 2013 was $37,895,000. The response to Data Request PGL AG 3.10 shows that the forecast of 2015 cross-charged labor expense includes the effect of $4,281,000 of wage rate increases from 2012 to 2015. This translates into an increase of 3.79% per year. Application of this increase in both 2014 and 2015 to the actual 2013 labor expense of $37,895,000 results in a projected 2015 labor expense of $40,818,000 charged to PGL. This is $4,963,000 less than the $45,781,000 of IBS labor expense forecasted by PGL.

The AG notes that the Companies' witness Ms. Kupsh disagreed with Mr. Effron's proposed adjustments to IBS cross-charged labor expenses. First, she stated that Mr. Effron did not allow for increased services provided to Peoples Gas and North Shore from

IBS. Second, she stated that he did not consider increased FTE employees at IBS. Third, she stated that he did not consider shifts in the allocation percentages based on utility inputs.

The AG asserts that these criticisms were invalid. While Mr. Effron agreed that he did not explicitly address each of the listed factors in his direct testimony, he did look at the actual increases in IBS cross-charged labor from 2012 to 2013 and the IBS cross-charged labor in the available months in 2014 compared to the corresponding period in 2013. Mr. Effron explained to the extent that the factors cited by Ms. Kupsh actually affected the IBS cross-charged labor expenses, the effects of those factors are implicitly included in the actual expenses in 2013 and 2014 to date. The AG notes that Ms. Kupsh's analysis fails to explain why actual increases in IBS cross-charged labor expenses have so far been significantly less than the increases forecasted by the Companies.

The AG contends that the cross-charged labor expense to North Shore in the first four months of 2014 was actually less than the expense in the corresponding period in 2013, and the cross-charged labor expense to Peoples Gas increased in the first four months of 2014 over the corresponding period in 2013, but at a lower rate than the increase forecasted. Based on the updated response to Data Request NS AG 16.04, the cross-charged labor expense to North Shore in the first six months of 2014 was still less than the expense in the corresponding period in 2013. The cross-charged labor expense to Peoples Gas in the first six months of 2014 was 5.19% greater than the expense in the corresponding period in 2013, only 1.4% more than the increase related to changes in wage rates. The AG submits that regardless of the underlying reasons for the increases in cross-charged labor being forecasted by the Companies, those increases simply are not taking place.

The AG adds that while Staff witness Daniel Kahle testified that he endorsed the Companies' IBS-charged labor forecast, he admitted that he did not perform any independent analysis to determine whether those three factors cited by the companies have actually resulted in increases to IBS cross-charged labor expense. He also admitted that he did not assess whether the available evidence or data from discovery indicates that the actual IBS cross-charged labor expenses have been increasing in the recent past.

The AG notes that Mr. Effron did, however, make one modification to his proposed adjustments to IBS-charged labor Peoples Gas (but not North Shore). As the actual increase in cross-charged labor expense to Peoples Gas in the first six months of 2014 was slightly greater than the increase related solely to wage rate changes, he instead used the actual six-month increase of 5.19% to project the cross-charged labor expense for 2014 and 2015. That results in a proposed reduction of $3,851,000 to labor cross changed from IBS to Peoples Gas. The AG explains that as the cross-charged labor expense to North Shore in the first six months of 2014 was less than the expense in the corresponding period in 2013, there was no need to modify his proposed adjustment to cross-charged labor expense to North Shore.

<u>Commission Analysis and Conclusion</u>

The Commission agrees with the Utilities and Staff and finds that the Utilities have provided sufficient evidence in support of their forecasted IBS labor costs cross charges.

The Commission also acknowledges that the AG analysis does not take into account various factors that impacted the increase in labor costs between 2013 and 2015 such as the increased services provided to the Utilities and the requisite increases in IBS labor to provide those services, the increased FTE employees at IBS, and a shift in the allocation percentages. The Commission finds that the record supports the Utilities' forecast and rejects the AG's proposals.

(ii) Benefits

Companies' Position

The Companies state that the AG's proposed adjustments to medical benefits cross-charged by IBS in all but one respect parallel the AG's arguments as to Peoples Gas' and North Shore's medical benefits costs, lack any valid basis, and should be rejected for the same reasons. *See* Section V.C.2.a of the Companies' Position above.

The Companies state that the new item that is added here by the AG is that Mr. Effron originally included a component in his proposed adjustments relating to the percentage of IBS medical benefits costs cross-charged to the Companies. However, after the Companies pointed out that Mr. Effron had not used the right percentages, he corrected his adjustments as to this aspect in his rebuttal. The Companies submit that the final paragraph of the AG's Initial Brief's discussion seems to suggest this aspect still is contested, but that it not the case.

The Companies contend that their figures should be adopted and notes that Staff agrees.

Staff's Position

Staff argues that the Commission should reject AG witness Effron's proposal to apply allocation percentages from 2013 to 2015 projected costs. Staff claims that percentages used to allocate 2015 projected costs should be based on the allocation base, such as the number of employees, approved by the Commission, for the period in which the costs are incurred.

AG's Position

The AG states that the test-year O&M expenses for both companies include employee benefit costs billed from IBS. IBS benefits billed are included in total employee benefits expense. The NS 2015 test-year IBS benefits billed expense is $1,868,000, and the PGL 2015 test-year IBS benefits billed expense is $11,250,000. The 2015 IBS benefits allocated to NS represent 6.6% of the total 2015 IBS benefits expense of $28,300,000. The 2015 IBS benefits allocated to PGL represent 39.8% of the total 2015 IBS benefits expense.

The AG explains that AG witness Effron proposed to adjust the forecasted IBS benefits expense allocated to NS and PGL in two separate adjustments. First, he modified the forecast of medical benefits expense. Second, he proposed modifying the percentages of IBS benefits expenses charged to NS and PGL.

Mr. Effron's proposed adjustment to the forecast of IBS medical benefits costs is similar to the adjustments to NS and PGL medical expenses. According to NS and PGL

Exhibits 12.1, IBS medical benefits costs are forecasted to increase from $9,808,000 in 2012 to $12,552,000 in 2015, an increase of 28%. But based on the response to Data Request PGL AG 1.53, the medical costs actually decreased from $9,808,000 in 2012 to $9,554,000 in 2013. Thus, the forecasted 2015 medical benefits costs of $12,552,000 in 2015 represent an increase of 31% over the actual 2013 medical benefits costs. The AG argues that while it may not be unreasonable to expect some increase in medical benefits costs from 2013 to 2015, it is unreasonable to forecast an increase of 31% over a two-year period in light of the data.

The AG states that Mr. Effron recommended that a reasonable escalation factor be applied to the actual 2013 medical benefits costs to project the 2015 test-year costs. Mr. Effron recommended that a 4.9% annual escalation rate be applied to the actual 2013 medical benefits for the purpose of projecting the 2015 test-year medical benefits expense. Mr. Effron's proposed modification to the projected IBS 2015 test-year medical costs reduces test-year medical benefits costs to $10,513,000 for the 2015 test year. The AG maintains that this is $2,039,000 less than the medical benefits costs projected by the Companies for IBS.

The second adjustment relates to the percentages of IBS benefits expenses charged to NS and PGL. NS Exhibit 12.2 and PGL Exhibit 12.2 show the allocation of IBS benefits expenses to NS and PGL. Both of these exhibits show increases from the actual 2012 allocation percentages to the forecasted 2015 allocation percentages, with the greatest increases taking place from 2013 to 2014. The AG states that in Data Requests AG NS 1.48 and AG PGL 1.56, the Companies were asked to explain the forecasted increases in the allocation percentages from 2013 to 2014. The Companies provided a brief description of the method used to allocate IBS benefits expenses to NS and PGL and also provided what they described as the actual allocation ratios for 2013, stating that the allocation percentages from IBS to NS and PGL have not changed significantly from actual 2013 to forecast 2014.

The AG asserts that the allocation percentages for 2013 in the responses to DRs AG NS 1.48 and AG PGL 1.56 are inconsistent with the actual allocation percentages in the responses to Data Requests AG NS 1.45 and AG NS 1.53. In the response to AG NS 1.48, the Company stated that the allocation percentage for NS in 2013 was 6.5%. The actual allocation percentage in the response to AG NS 1.45 is 5.7%. According to the AG, the forecasted allocation percentage of 6.5% for 2014 is a significant increase from the actual 2013 allocation percentage, which NS has not explained.

In the response to AG PGL 1.56, the Company stated that the allocation percentage for PGL in 2013 was 39.0%. The actual allocation percentage in the response to AG PGL 1.53 is 34.1%. The AG states that the forecasted allocation percentage of 39.0% for 2014 is a significant increase from the actual 2013 allocation percentage, which PGL also has not explained.

The AG asserts that the actual 2013 allocation percentages for 2013 represent decreases from the actual 2012 allocation percentages. The AG notes that the Company had forecasted decreases from 2012 to 2013, but the actual decreases were greater than forecasted. The Companies have not justified the jumps in the allocation percentages from 2013 to the forecasted 2014 allocation percentages, which approximate the forecasted 2015 test-year allocation percentages. The AG contends that the forecasted 2015 test-year allocation percentages should be modified.

The AG explains that to reflect the actual activity AG witness Effron recommends that the actual 2013 allocation percentages be used to allocate the IBS benefits expense to NS and PGL. The actual 2013 allocation percentages are 5.7% for NS and 34.1% for PGL.

The AG notes that NS/PGL witness Kupsh disagreed with Mr. Effron's proposed adjustments to IBS cross-charged benefits expenses. She opined that the 2013 actual allocation percentages and the forecasted 2015 allocation percentages that Mr. Effron relied on in his direct testimony to quantify his proposed adjustments were not stated on comparable bases. She stated that using comparable bases, the actual allocation percentage for North Shore in 2013 would be 6.2%, rather than 5.7%, and the actual allocation percentage for Peoples Gas in 2013 would be 37.4%, rather than 34.1%.

The AG states that Mr. Effron agreed that the actual percentage allocation factor in 2013 should be calculated on a basis consistent with the calculation of the allocation factor for the 2015 test year, and modified his calculation of the adjustment to the 2015 IBS cross-charged benefits accordingly. When combined with the adjustment to the Medical portion of the Benefits, the adjustment to the allocator results in adjustments of $1,258,000 for PGL and $228,000 for North Shore.

The AG asserts that the Companies failed to justify use of a percentage allocator that is inconsistent with actual activity and submits that Mr. Effron's adjustment should be adopted by the Commission.

Commission Analysis and Conclusion

The Commission agrees with the Companies and Staff and finds that for the same reasons discussed in the Commission Analysis and Conclusion section in Section V.C.2.a of this Order, the AG's proposed adjustments to medical benefits expense, including medical benefits cross-charged by IBS, should be rejected.

(iii) Postage

Companies' Position

The Companies state that the AG's proposed adjustments to the Companies' forecasted cross charged postage expense are incorrect and should be rejected. The AG's proposal considers only a flat postage rate increase, and ignores the expected increase in volume of mail, which is driven by the ICE project. The Companies note that Staff also opposes the AG's postage adjustments.

The Companies state that the AG calls the forecasted 2015 level of this expense "unexplained", but this is nothing more than the AG seeking to define away the expected increases in postage rates and volume of mail as explanations. The Companies maintain that the AG admits that those two factors could increase the expense level, although the AG claims that the Companies did not sufficiently explain how they will result in the forecasted levels.

The Companies add that the AG seeks to diminish the fact that Staff witness Mr. Kahle agrees with the Companies' figures and opposes the AG's proposed adjustments, by pointing to the fact that he did not do an "independent analysis" of the likelihood of the volume increases. The Companies maintain that does not alter the fact that Mr. Kahle's review led him to conclude that the Companies' figures should be approved. Additionally, Mr. Kahle's rebuttal testimony made clear that he had reviewed the Companies' support for the increases.

The Companies contend that the AG cannot ignore the effect of the expected increases in postage rates and the increase in the volume of mail on the Companies' forecasted cross charged postage expense. The Companies submit that their figures should be adopted.

Staff's Position

Staff argues that the Commission should reject AG witness Effron's proposal to reduce postage expense charged to the Companies from IBS. Staff notes that Mr. Effron considers the amount of the proposed increase to be unreasonable, but does not make an argument against the Companies' rationale for the proposed increase. The Companies propose increasing postage expense because of an expected increase in the volume of mailings as well as a postage rate increase. According to Staff, the Companies' rationale is reasonably based on the support provided for the increase.

AG's Position

The AG explains that IBS allocates postage expense to both NS and PGL. NS test-year operation and maintenance expenses include $914,000 of postage expense allocated from IBS. PGL test-year operation and maintenance expenses include $4,799,000 postage expense allocated from IBS.

The AG states that AG witness Effron proposed to adjust the test-year postage expenses based on the Companies' unexplained and inflated forecasted 2015 postage expense. For NS, the allocation represents an increase of 38% over the actual postage expense of $648,000 in 2013. The forecasted 2015 postage expense for PGL represents an increase of 20% over the actual postage expense of $4,170,000 in 2013. The AG asserts that projected increases of this magnitude over two years are not reasonable. Mr. Effron noted that while it would not be unreasonable to include a small allowance for increases in postage rates from 2013 to 2015, allowances should be no more than 10%, based on annual increases in postage rates in recent years. Mr. Effron calculated that escalating the actual 2013 postage expense by 10% would result in a reduction of $201,000 to the NS forecasted 2015 test-year postage expense and $212,000 to the PGL forecasted 2015 test-year postage expense.

The AG notes that NS/PGL witness Kupsh disagreed with the AG-proposed postage expense adjustments. She claimed that Mr. Effron did not allow for increases in volume, such as increases related to ICE project-related volume. But Ms. Kupsh never explained how the increases in volume will result in the specific increases in postage expense that the Companies are now forecasting. The AG adds that Ms. Kupsh cites factors that could potentially increase postage in volume, but she does not show how such increases in volume would lead to the magnitude of increases reflected by the

Companies in their forecasts of 2015 test-year postage expenses. The AG states that Ms. Kupsh appears to be claiming that the projected increases are reasonable because that is what the Companies forecasted. The AG contends that the Companies simply did not provide the necessary detail and document the forecasted increases in postage expenses to justify the forecasted increases.

The AG notes as well that Staff witness Kahle endorsed the Companies' forecasts, but conceded during cross examination that he simply relied on the Companies' numbers and conducted no independent analysis of his own. The AG submits that Mr. Effron's well-supported adjustments, based on actual data, should be adopted by the Commission.

Commission Analysis and Conclusion

The Commission approves the Utilities' forecasted cross charged postage expense. The Commission agrees with the Utilities and Staff that the effect of the expected increase in postage rates and the increase in the volume of mail on the Utilities' forecast cannot be ignored. The AG has provided no evidence supporting its proposed adjustments to the Utilities' forecasts.

(iv) Legal (NS)

North Shore's Position

The Companies state that the North Shore legal budget was developed through consultation of the business team and the legal department, based not only on historical legal expenses but also expected future requirements and demands for services.

The Companies contend that the AG's proposed adjustment should not be adopted. The AG proposes to adjust the forecasted legal expenses cross-charged to North Shore, essentially on the grounds that this cost has been flat and that the Companies did not provide sufficient data to support the forecast, and Staff agrees. The Companies state that places no weight on how the forecast of this item was developed and that the North Shore figure should be approved.

Staff's Position

Staff finds that the Commission should adopt Mr. Effron's proposed adjustment to legal expenses. AG witness Effron proposes to reduce projected legal expenses for North Shore. Staff states that Mr. Effron cites not only to historical trends, but also to the lack of a defined rationale for the projected increase.

AG's Position

AG witness Effron proposed an adjustment to the legal expense charged by IBS to North Shore. Mr. Effron explained that NS test-year operation and maintenance expenses include $618,000 of legal expense allocated from IBS. This represents an increase of 61% over the actual legal expense of $383,000 in 2013. In response to Data Request NS AG 1.55, NS explained that the increase is based on the assumption that outside legal fees will increase because they have remained flat since 2008. Mr. Effron noted that this is hardly a justification for the steep increase NS projected. The AG asserts that if anything, the alleged rationale seems like more of an explanation of why there should be a forecast of no increase in legal fees.

The AG explains that in order to reflect actual data, and in light of the absence of any valid explanation for the assumed increase, AG witness Effron recommended that test-year legal expenses reflect the average actual legal fees for the years 2012 and 2013 which approximates the five-year average for the years 2009 through 2013. The average actual legal expense for 2012 and 2013 was $446,000. The AG notes that this is $172,000 less than the 2015 test-year legal expense forecasted by NS.

The AG notes that NS/PGL witness Kupsh disagreed with the proposed adjustment. She argued that the legal services budgets are based on consultation between the business team and the legal department, and that the 2015 budget is based upon assumptions regarding the expected demands and requirements of North Shore for legal services, as well as reasonable forecasts of the costs of those services. Again, however, no actual data or computations were discussed or revealed to justify a 61% increase in this expense item. As Mr. Effron noted, the Companies' explanation is no more than a description of the process that is used to forecast legal expenses. The AG finds that Mr. Effron's proposal to use an average of actual legal expense for 2012 and 2013 should be adopted by the Commission.

Commission Analysis and Conclusion

The Commission agrees with the AG and Staff and finds that the Utilities have not provided sufficient evidence justifying their forecasted legal expenses cross-charged to North Shore. The Utilities argued that the IBS legal expense allocated to North Shore was developed based on historical legal expenses and expected future requirements and demands for services but provided no explanation of what the expected future requirements and demands for services represent or why they result in the forecasted escalation in expense. The Commission adopts the AG's proposed adjustment to the legal expense charged by IBS to North Shore.

(v) Integrys Customer Experience ("ICE") Project

(a) Return on Assets and Depreciation

Companies' Position

The Companies explain that the ICE project is scheduled to go into service fully in 2015. This project will unify the Companies' customer information systems with those of other Integrys companies, providing significant benefits to customers, including, among other things, improved efficiency, productivity, and standardization of internal delivery, and improved and enhanced billing, collections, call center and service related offerings. The Companies state that they provided evidence supporting the portions of the forecasted ICE project costs allocated to the Companies. The Companies note that in direct testimony, Companies' witness Ms. Gregor described the Companies' established budgeting and forecasting processes, and overviewed the careful steps through which the 2015 forecasts were prepared, starting from the foundations of the approved 2014 budget prepared in the Fall of 2013. The Companies further claimed that these processes resulted in the forecasted 2015 financial statements that an independent Certified Public Accountant, Deloitte & Touche LLP, confirmed were prepared in accordance with the applicable accounting rules (in accordance with 83 Ill. Adm. Code § 285.7010). The Companies offer that Ms. Gregor also discussed all significant variances in operating expenses from 2012 to forecasted 2015, noting, among other things, that the second largest factor in the increase in the category of Customer Accounts expense was the combination of increased call center costs and costs of the ICE project.

The Companies add that in direct testimony, Companies' witness Ms. Kupsh discussed the IBS budgeting and forecasting process, which parallels those of the Companies, and variances in the IBS costs cross-charged to the Companies from 2012 to forecasted 2015, noting that the third largest factor was the ICE project.

The Companies submit that AG witness Mr. Effron proposes to reduce the portion of forecasted 2015 ICE project depreciation and capital investment costs cross-charged to the Companies using simple math, extrapolating from costs from certain months at the beginning of 2014 and then multiplying by them to reach an annualized figure which he uses to estimate 2015 costs. However, the Companies state that his proposal (1) arbitrarily ignores the forecasted expenditures and plant in service activity, (2) ignores the fact that IBS only bills the Companies for assets that are in service, and (3) while work on the project began in 2012, only a small portion of the ICE project was in service in the months of 2014 on which his proposal is based, making the data from which Mr. Effron extrapolates completely unrepresentative of 2015 costs.

Staff also rejects Mr. Effron's proposed adjustments, noting the expected in service date of the full ICE project and the lack of factual support for Mr. Effron's proposal. The Companies assert that at the evidentiary hearing the AG cross-examined Staff witness Ms. Hathhorn about the fact that the Companies' 2015 forecasts do not reflect any cost savings resulting from the ICE project, but the evidence shows that to be correct. Ms. Hathhorn pointed out that the Companies have been expending money on their portions of the ICE project from 2012 to now and will continue spending through 2015, that the project as a whole will go into service in 2015, and that savings are not expected to occur until 2016.

The Companies contend that the AG essentially just wishes away the above facts. The AG points to data from the first four months and the first six months of 2014, without even considering the above facts, including, among others, the fact that only a small portion of the ICE project was in service in those months, meaning that the costs then do not reflect the costs when the project is in service in 2015. The AG notes that Mr. Effron claimed that his looking at the data from the first six months of 2014 somehow implicitly incorporated the above facts. The Companies argue that the first half of 2014 data does not take into account that the costs are charged to the Companies only to the extent the project is in service.

The Companies also note that in Mr. Effron's rebuttal, he added raw speculation to the implied effect that, if the WEC-Integrys transaction proposal is approved, then the ICE project might be cancelled. The Companies hold that issue belongs in ICC Docket No. 14-0496, not here. The Companies argue that Mr. Effron cited no relevant facts to support his speculation, and it does not make sense. The ICE project work already is well along, even though only a small portion of the project is in service. For example, the project is approximately 90% complete with respect to coding and some system tests have started. The project is expected to be in service fully in 2015. The WEC-Integrys transaction, if approved, is expected to close in Summer 2015. The Companies contend that Mr. Effron's conjecture lacks logic and is not a proper basis for a Commission decision.

The Companies note too that, on October 30, 2014, the AG filed a "Motion to Admit New Information", which sought to add to the evidentiary record a copy of the Companies' DR response ("DRR") AG 3.05 from the reorganization case, Docket No. 14-0496. The Companies state that the Motion offered panoply of assertions and innuendo relating to the ICE project costs issue. The Companies note that they filed their objections to the Motion on October 31st, as per the schedule ordered by the ALJs and that the AG filed a reply on November 3rd that contained additional assertions and innuendo. The Motion was granted on November 5th.

The Companies incorporate their objections to the Motion, including their objections under Ill. R. Ev. 401 and 403. In their Reply Brief, the Companies stated that they believe it is not fair or proper to expect them to anticipate and address in briefing what the AG may claim in its Reply Brief based on reorganization case DRR AG 3.05. The Companies further state that the Commission must base its decision on the evidence in the record and in accordance with the applicable law, including due process principles, but the Companies have not had notice and an opportunity to submit evidence responding to what the AG's Reply Brief will claim in relation to that DRR.

The Companies contend that the existing evidentiary record and DRR AG 3.05 itself in context show that whatever the AG may claim based on the DRR, it does not provide any basis for questioning the 2015 forecasted ICE project costs, nor for adopting AG witness Mr. Effron's proposed adjustments. The Companies note that the AG already argued for a scenario in which the ICE project goes ahead as scheduled but costs less than forecasted, and alternatively for a scenario in which the project is cancelled, as previously discussed. The Companies contend that the AG now, in an apparent effort to exhaust all options, appears to plan to argue for a scenario based on older, non-updated information reflected in DRR AG. 3.05.

The Companies assert that at the evidentiary hearing on September 23rd, the AG showed Companies witness Ms. Kupsh AG Cross Ex. 8. AG Cross Ex. 8 consists of: (1) the Companies' data request response to Staff data request DLH 35.01 in the instant rate cases and (2) the Joint Applicants' response to AG data request 2.13 in Docket No. 14-0496. DR DLH 35.01 asks about DRR AG 2.13. The Companies further note that at this time, counsel for the Companies explained that Companies witness Lisa Gast, as to whom cross-examination had been waived, was the affiant for DRR DLH 35.01.

The Companies state that as can be seen in AG Cross Ex. 8, reorganization DRR AG 2.13 related to an exhibit the Joint Applicants filed in the reorganization Docket. That exhibit was offered to meet the requirement of Section 7-204(a)(7) of the PUA that, in brief, the reorganization applicants provide a five year forecast showing the utility's capital requirements. The Companies explain that DR AG 2.13 is focused on a single item (an assumption) in JA Ex. 4.1. Reorganization data request AG 3.05 is a follow-up to data request AG 2.13, and data request AG 3.05 also relates to that same item in JA Ex. 4.1.

The Companies contend that AG Cross Ex. 8 (in DRR DLH 35.01) explains, however, that the information in JA Ex. 4.1 that is referenced in reorganization DRR AG 2.13 was derived from the Companies' 2013 Long Term Financial plans prepared in Spring 2013, and that the assumptions used in those plans were based on budget data from Summer and Fall 2012. Further, the Companies assert that AG Cross Ex. 8 (in DRR DLH 35.01) also explains that, since then, an updated forecast was developed, and that the 2015 test year data used by the Companies in these rate cases reflects the updated forecast, which includes the forecasted costs (and the absence of savings) in 2015.

The Companies emphasize that the AG considered asking that Ms. Gast be called for cross-examination on this subject, but the AG ultimately agreed with the Companies that the AG would move AG Cross Ex. 8 into evidence and not call Ms. Gast as a witness.

The Companies state that the AG's October 30th Motion brought up assertions about possible savings in 2015 due to the ICE project. The Companies' October 31st response explained, among other things, that reorganization case DRR AG 3.05 itself showed a forecast of no savings in 2015. DRR AG 3.05 did refer to costs that would not be incurred in 2015 if the ICE project continued, but the Companies' forecasts reflect that the ICE project is continuing, and thus they include no such avoided costs. More specifically, the attachment to reorganization Docket DRR AG 3.05 (on page 1) is dated September 17, 2012. The attachment (on page 2, *et seq.*) refers to "Hard O&M Benefits" and "Avoided" costs, but it shows no "Hard O&M Benefits" until 2016. The attachment shows "Avoided" Costs beginning in 2013, but "Avoided" costs are not savings; rather, they are costs that IBS has not incurred but which it would incur if it did not implement the ICE project. The Companies note that the AG's November 3rd reply did not make any further assertions about possible savings.

Thus, the Companies state that the AG's Reply Brief presumably is going to argue from reorganization case DRR AG 3.05, which followed up on information that AG Cross Ex. 8 already has explained is based on budget data from Summer and Fall 2012 and thus does not reflect the later information reflected in the Companies' 2015 rate case forecasts. The Companies assert that the rate case data have been provided by the Companies to address the forecasted 2015 test year. Reorganization case DRR AG 3.05 necessarily will be inconsistent, because the two sets of information were prepared at different points in time. The Companies contend that DRR AG 3.05 is no basis for approval of the AG's proposed adjustments to the ICE project costs.

<u>AG's Position</u>

Test-year expenses include depreciation and return on assets ("ROA") related to IBS hardware and software for the ICE project. The AG states that as shown in the response to Staff Data Request DLH 5.07, Attachment 1, the budgeted depreciation and ROA on the ICE project is forecasted to increase from $11,000 in 2012 to $1,378,000 in 2015 for NS and from $56,000 in 2012 to $7,263,000 in 2015 for PGL.

According to the AG, the problem with this forecast is that the depreciation and ROA related to the ICE project are not increasing as forecasted. The Companies provided updates of the actual ROA and depreciation on the ICE project in 2014 through June, and these updates show little change in the rate of expense from the first four months of 2014. Based on the actual experience in the first half of 2014, the annualized ICE ROA and depreciation from IBS to North Shore is $124,000, and the annualized ICE ROA and depreciation expense from IBS to Peoples Gas is $652,000. The AG argues that this compares to forecasted expenses of $1,378,000 to North Shore and $7,263,000 to Peoples Gas for the 2015 test year.

The AG notes that Mr. Effron updated his adjustments based on the actual expenses for the six months ended June 30, 2014. On Schedule DJE NS C-4 attached to his Rebuttal testimony, Mr. Effron calculated a reduction of $1,254,000 to 2015 test-year ICE depreciation/ROA allocated from IBS to NS. On Schedule DJE PGL C-4, Mr. Effron calculated a reduction of $6,611,000 to 2015 test-year ICE depreciation/ROA allocated from IBS to PGL. The AG asserts that the updates based on additional information in 2014 do not result in significantly different annualized levels of expenses for the adjustments proposed in Mr. Effron's direct testimony.

The AG adds that NS/PGL witness Kupsh criticized Mr. Effron's proposed adjustment to forecasted 2015 ROA and Depreciation related to the ICE program, arguing that his calculations are inaccurate and inappropriate. In his Rebuttal testimony, Mr. Effron noted that Ms. Kupsh claims that his calculations are inaccurate, but does not cite any errors or inconsistencies in the calculations. The AG counters that while Ms. Kupsh may disagree with Mr. Effron's proposed adjustments that does not mean that his calculations are erroneous.

The AG continues that Ms. Kupsh further asserted that the proposed adjustments are inaccurate because they ignore forecasted expenditures and plant-in-service activity. The AG states that to the extent expenditures and plant-in-service activity have actually affected the cross charges for ROA and depreciation on the ICE project, such factors are implicitly incorporated into the adjustments Mr. Effron is proposing. The AG maintains that the Companies are forecasting substantial increases in the ROA and depreciation on the ICE project, but so far, based on the actual experience in 2014, there is little evidence that such increases are actually taking place.

Ms. Kupsh claims that the only accurate measures for the ICE ROA and depreciation expenses are the Companies' forecasted 2015 test-year expenses. The AG contends, however, the actual experience does not provide any indication that the actual level of expenses is increasing to anything like the level of expenses forecasted by the Companies. According to the AG, the Companies simply failed to provide evidence that justified the forecasts. The AG states that ICE ROA and depreciation expenses included in test year operation and maintenance expense should be modified, consistent with AG Effron's proposal.

The AG states as well that in the Companies' application for merger proceeding, Docket No. 14-0496 ("Merger docket"), the Joint Applicants, which include both Peoples Gas and North Shore, provided on October 22, 2014 a data request response (DRR AG 3.05) with a Confidential Attachment 1, following the completion of the evidentiary hearings and filing of the Initial Briefs in the instant docket. The AG explains that the Response and Attachment detail how future costs of the ICE project will be incurred and notes the information shown on Attachment 1 to the Response differs significantly from information provided by the Companies in the instant consolidated docket. The AG states that the response to DRR 3.06 in the Merger dock*et al*so confirms that the forecasted ICE expense numbers provided in this rate case are entirely inconsistent with data supplied in the Merger docket. The AG submits that this discovery in the Merger docket contradicts everything the Companies have stated about both the amount of allocated costs and the timeline of when costs and benefits of the ICE project will be incurred. The AG concludes that the Companies have failed in their burden of proving that their 2015 test year forecast of these amounts is reliable and that the Commission should reject the impact of the Companies timeline and require an appropriate balancing of costs and benefits of the ICE project.

Staff's Position

Staff does not support the AG proposed adjustments for the Companies' ROA related to IBS hardware and software and other non-labor expenses for the ICE Project. Staff notes that ICE is a consolidated IBS customer system, scheduled to go in service in 2015 and that Mr. Effron's calculations use annualized 2014 expenses to adjust the 2015 test year. Ms. Hathhorn testified that it does not appear that annualizing the historical costs of this project is appropriate. Staff finds that Mr. Effron's analysis does not account for the fact that the Companies forecast the ICE system to be placed in service in 2015 and placing the asset into service will trigger the larger depreciation and ROA charges from IBS at that time. Staff adds that Mr. Effron also provided no evidence to the contrary that the majority of the non-labor expenses will begin in 2015 as the software goes in service.

Staff mentions that the AG also called into question whether or not the increased ICE costs would be incurred due to the announced acquisition of Integrys by WEC. The AG opines that the ICE project would be a likely target for operational and financial benefits referenced in the announcement of the acquisition. Staff maintains that the rates in the instant proceeding must reflect only test year costs, and anticipated savings outside the test period are not allowed in rates at this time. Staff discussed at the evidentiary hearing the Integrys Board of Directors' approval of the ICE document provided in discovery, confirming the 2015 in service date, and that savings are projected for 15 years. Staff recommends the Commission reject the AG adjustments for the ICE project.

Commission Analysis and Conclusion

The Commission agrees with the Utilities and Staff and finds the record evidence supports their position. The Commission further finds that the AG's proposal does not consider the Utilities' forecasted expenditures and plant in service activity and that IBS only bills the Utilities for assets that are in service. The AG's proposal also fails to consider that while work on the project began in 2012, only a small portion of the ICE project was in service in the months of 2014 on which Mr. Effron's proposal is based. The Commission notes as well that issues and speculation related to Docket No. 14-0496 do not provide reasonable grounds for rejecting the more recent forecasts of ICE project costs.

(b) Non-Labor

Companies' Position

The Companies state that the evidence supports their forecasted 2015 "non-labor" costs cross-charged to the Companies in relation to the ICE project. The Companies disagree with AG witness Mr. Effron's attempt to reduce the Companies' forecasted costs. The Companies point out that Mr. Effron's proposal is based on looking at costs from only the first four or six months of 2014, yet he assumes they are fully representative of the 2015 costs.

The Companies state that Mr. Effron's proposal fails to discuss relevant facts and lacks a factual foundation as did his first two ICE-related adjustments. The Companies add that Staff agrees that the AG's proposal lacks merit.

The Companies also note that AG witness Mr. Effron suggested that the proposed WEC TEG transaction somehow means that there is a chance the ICE project will be cancelled but this is merely a conjecture that lacks any sound basis. The Companies contend that the AG's proposed adjustments should be rejected.

Staff's Position

See preceding section for the discussion of Staff's position on both the ICE Project Return on Assets and Depreciation as well as Non-Labor adjustments.

AG's Position

The AG states that in addition to the ROA/Depreciation-related expenses, Mr. Effron also proposed to adjust the forecasted 2015 test-year non-labor ICE expenses. Once again, based on the information provided by the Companies, the forecasted increases in the ICE Non-Labor expenses are not taking place at the forecasted rates. Updates of the actual expenses in 2014 through June mirror the activity documented during the first four months of 2014. The AG asserts that based on the actual experience in the first half of 2014, the annualized non-labor ICE expenses from IBS to North Shore is $252,000, and the annualized non-labor ICE expenses from IBS to Peoples Gas is $1,352,000. This compares to forecasted expenses of $1,504,000 to North Shore and $9,058,000 to Peoples Gas for the 2015 test year.

The AG maintains that Mr. Effron's updated adjustment calculated a reduction of $1,252,000 to 2015 test-year non-labor ICE expenses allocated from IBS to NS based on annualized data from the first six months of 2014. On Schedule DJE NS C-4, attached to his Rebuttal testimony, he calculated a reduction of $1,252,000 to 2015 test-year non-labor ICE expenses allocated from IBS to NS. On Schedule DJE PGL C-4, he calculated a reduction of $7,706,000 to 2015 test-year ICE depreciation/ROA allocated from IBS to PGL. The AG notes that the updates based on additional information in 2014 do not result in significantly different annualized levels of expenses from those presented in Mr. Effron's direct testimony.

The AG adds that NS/PGL witness Ms. Kupsh offered a similar criticism of Mr. Effron's proposed adjustment to forecasted 2015 other non-labor ICE expenses that will be cross-charged from IBS to NS and PGL. She claims his calculations are inaccurate and inappropriate. However, Ms. Kupsh does not cite any errors or inconsistencies in the adjustment calculations, but instead claims that Mr. Effron ignored forecasted operation and maintenance expenses for ICE. The AG states that Mr. Effron did not ignore the forecasts of operation and maintenance expenses for ICE. Rather, the actual data supplied by the Companies shows that other non-labor ICE expenses are not increasing as forecasted. The AG asserts that the Companies are forecasting substantial increases in the non-labor ICE expenses, but there is little evidence that such increases are actually taking place. As with the ROA and depreciation on the ICE project, this actual data should not be ignored.

The AG mentions that Ms. Kupsh claims that the only accurate measures for the non-labor ICE expenses are the Companies' forecasted 2015 test year expenses. However, the actual experience does not provide any indication that the actual level of expenses is increasing to anything like the level of expenses forecasted by the Companies. The AG submits that other reasons exist that justify a modification of the Non-Labor ICE expense forecast such as the announcement of the acquisition of Integrys by WEC. That announcement made reference to "operational and financial benefits" that are clear, achievable and compelling and states that the transaction will be accretive to Wisconsin Energy's earnings per share in first full calendar year after closing, with anticipated closing for the merger in the summer of 2015. In his rebuttal testimony, the AG finds that Mr. Derricks did not dispute the potential for "operational and financial benefits" but, rather, cites uncertainties regarding the closing of the transaction.

The AG continues that Mr. Effron testified that while it is not 100% absolutely certain the acquisition of Integrys by Wisconsin Energy Corp. will close exactly as planned, based on experience, he stated that he believes it is more likely than not that the acquisition will take place. Assuming that the acquisition does close, the AG finds that it would seem that the increased costs associated with the ICE project would be a likely target for the "operational and financial benefits" referenced in the announcement of the acquisition, in that the savings could be achieved by simply avoiding increases in expenses rather than having to eliminate expenses that are already being incurred. The AG contends that the increases associated with the ICE ROA/depreciation and other non-labor expenses are by no means certain to the extent that they should be incorporated into 2015 test year operation and maintenance expenses.

The AG concludes that for all of these reasons, the Commission should adopt Mr. Effron's ICE adjustments, which are rooted in data that reflects actual annualized experience for the 2014 period. The Companies simply have not provided credible evidence that the significant jump in ICE expenses forecasted for the 2015 test year are likely to occur – particularly in the midst of a likely corporate acquisition.

Commission Analysis and Conclusion

The Commission finds that the record evidence supports the views of the Utilities and Staff. The Commission also finds that the AG's proposal lacks factual support. The AG's proposal is based on costs from only the first four or six months of 2014 but states that it is fully representative of the 2015 costs. The Commission disagrees. Further, issues and speculation related to Docket No. 14-0496 do not provide reasonable grounds for rejecting the more recent forecasts of ICE project costs.

b. Advertising Expenses

Companies' Position

The Companies note that in rebuttal, they accepted a total of $25,000 of Staff's proposed downward adjustment to advertising expenses for North Shore Gas and Peoples Gas, but rejected Staff's proposed adjustments removing $4,000 of expenses for North Shore and $51,000 of expenses for Peoples Gas because those remaining challenged expenditures were recoverable under Section 9-225 and were also recoverable as charitable expenditures under Section 9-227. The Companies add that although CCI did not submit evidence on this issue, it supports Staff's position.

The Companies hold that Staff's (and CCI's) primary contention is that these expenditures proposed for removal are "of a promotional, goodwill or institutional nature" under Section 9-225 of the Act and, therefore, not recoverable. The basis for Staff's and CCI's argument that these "advertising expenditures" are not properly recoverable is that the Companies classified them, for accounting purposes, under the Companies' Account 909 – Informational and Institutional Advertising. As those "advertising expenditures" are classified in Account 909, Staff and CCI derive the notion that these expenditures are simply used to put the Companies' name in a philanthropic light.

The Companies explain that Section 9-227 of the Act provides for recovery as an operating expense of donations "for the public welfare or for charitable, scientific, religious, or educational purposes, provided that such donations are reasonable in amount." Section 9-225 of the Act addresses advertising expenditures and identifies several categories that "shall be considered operating expenses for gas or electric Companies." 220 ILCS 5/9-225(3). The Companies assert that the expenditures that Staff seeks to disallow support the sponsorship of charitable events including: the Chicago Children's Choir, the Chicago Public Library Foundation, the Children First Fund, Friends of Holstein Park, the Hispanic Heritage Organization, the Museum of Science and Industry, Red Moon Theater, Children of Purpose, Preservation Foundation of Lake County, the University Center of Lake County, and the Waukegan Public Library and other similar events. The Companies contend that the funding of those charitable events supports a range of cultural and educational activities for charitable organizations within Chicago and Cook and Lake Counties. Further, the Companies note that for most of the sponsorships of those charitable events, the Companies use their presence at the events to provide information about the Companies' energy efficiency and energy assistance programs. As a result, the Companies contend that "promotion" of utility energy efficiency and energy assistance programs is not "promotional advertising" for which recovery is prohibited, but is a form of permissible and recoverable advertising under Section 9-225(3)(a), (e) and (i) of the Act, 220 ILCS 5/9-225(3)(a), (e) and (i). Further, the Companies submit that support of charitable events is recoverable under Section 9-227 of the Act, 220 ILCS 5/9-227. Thus, the Companies assert, the expenditures that Staff's testimony proposed to disallow, other than the amounts accepted by the Companies' rebuttal and surrebuttal, are expenditures that are recoverable under Sections 9-225 and 9-227.

The Companies contend that contrary to Staff's assertions, the Companies' "advertising expenditures" are not of a promotional, goodwill or institutional nature, but instead are recoverable expenses that are charitable in nature under Section 9-227 of the Act (220 ILCS 5/9-227) or are recoverable as expenditures supporting the promotion of the Companies' energy efficiency and energy assistance programs under Section 9-225 of the Act (220 ILCS 5/9-225). The Companies presented detailed descriptions of the "advertising expenditures" demonstrating the charitable purpose and nature of the expenditure.

Further, the Companies assert that Staff's contention that these expenditures should not be recoverable lacks merit, as Staff's theory that Section 9-225 requires or warrants disallowance of costs that put the Companies "in a philanthropic light" is not supported by the language or past interpretations of Section 9-225. The Companies contend that such a theory essentially would read Section 9-225 to mean that if the Companies spend money on a good purpose that benefits customers or communities, unless the Companies do it anonymously, then the costs should be unrecoverable. As a result, the Companies argue, the Staff theory is both unreasonable and counter-productive. The Companies also contend that the Staff theory reads Section 9-225 in a manner that is inconsistent with the express allowance of charitable contributions costs recovery under Section 9-227 of the Act, 220 ILCS 5/9-227. The Companies note that the Commission previously rejected the Staff's argument that an expenditure for a charitable purpose under Section 9-227 that puts the Companies' name in a "philanthropic light" should not be recoverable. Docket Nos. 12-0511/12-0512 (Consol.), Order at 164. The Companies assert that the Commission rightly determined that the nature of the expenditure is the determinative factor for rate recovery. *Id.* Further, the Companies argue that the particular accounting entry of these expenditures under Account 909 - Informational and Institutional Advertising also is not determinative of recovery. The Commission ruled in Docket Nos. 12-0511/12-0512 (Consol.) that:

> …the Commission believes the nature of the expense is more important and declines to adopt Staff's position that these expenses can not be considered as charitable contributions because the Companies initially recorded them as advertising expenses.

Docket Nos. 12-0511/12-0512 (Consol.), Order at 164.

The Companies also maintain that, in following the Commission's direction in Docket Nos. 12-0511/12-0512 (Consol.), the Companies significantly changed their processes for distinguishing expenditures that were charitable in nature from other expenditures. The Commission in Docket Nos. 12-0511/12-0512 (Consol.) said that the Commission:

> …believes the Companies must be more careful in distinguishing sponsorship and institutional expenditures that are allowable for charitable purposes and those that are allowable advertising expenses.

Docket Nos. 12-0511/12-0512 (Consol.), Order at 164.

The Companies note that Staff argues that the Companies were not "more careful" in distinguishing the nature of expenditures, contrary to the direction of the Commission in Docket Nos. 12-0511/12-0512 (Consol.). However, the Companies state that they greatly expanded the process for screening and categorization of charitable, sponsorship and institutional expenditures and developed more detail descriptions of the informational and institutional "advertising expenditures" made under Account 909.

The Companies indicate the following changes to their process to distinguish these "advertising expenditures." The Companies have created a more detailed review process for requests for the Companies' participation in a charitable, sponsorship or institutional event, to better insure that such expenditure is for a rate-recoverable purpose. The Companies explain that they first determine if a particular request goes to a rate recoverable-purpose such as an educational, safety, environmental, charitable, human and health services, or community development. If the Companies determine that: (1) such expenditure would fulfill a strategic purpose, whether for the charitable institution, the community and/or customers, (2) such expenditure will further build the Companies' relationship with that charity, the community, and/or customers, (3) the requestor has a strong reputation, including the strength of its management and board, (4) there is a need for a contribution/spending, and (5) such expenditure will be impactful in achieving the charity's, community's, or customers' needs, then the expenditure has met the necessary screening criteria for potential funding. The Companies also review the funding request to determine: (1) if there are multiple funding sources; (2) does the Companies' participation enhance the possibility of other entities funding the educational, safety, environmental, charitable, human and health services, or community development need; (3) is the funding request realistic for the goal; and (4) what is the Companies', its employees', and their retirees' involvement with the requestor and goal.

The Companies state that, once the decision has been made to fund the request for sponsorship and spending, the expenditures are classified into one of two categories: (a) sponsorships or expenditures where information and education related to safety, energy efficiency, energy assistance, and/or billing and payment options are communicated to customers and the community; and (b) sponsorships or expenditures where community services are enhanced and benefited for charitable purpose. Last, the Companies provide expanded descriptions of the expenditure/charitable funding, the organization that is being supported, the nature of the expenditure and cause or program being promoted or advanced. The Companies explain that these changes are a direct result of Docket Nos. 12-0511/12-0512 (Consol.) and serve to distinguish recoverable, charitable expenditures from non-recoverable expenditures under Account 909.

The Companies state that they expect additional guidance for the classification of expenditures related to charitable spending pending the outcome of the ongoing rulemaking concerning the rate case treatment of charitable contributions in Docket No. 12-0457.

The Companies note that Staff argues that the expenditures should not be recoverable as Staff and the other parties would not have the opportunity to adequately and timely review the expenditures for compliance with Section 9-227. The Companies strongly assert that this contention is nonsense, and that Staff has had no issue contending that the "advertising expenditures" should not be recoverable. The Companies state that the "advertising expenditures" that Staff seeks to disallow were brought to the attention of all of the parties in the Companies' direct testimony. Further, the Companies assert that full and expanded descriptions of the expenditures were provided in discovery and included in the Companies' rebuttal exhibits. The Companies contend that they have identified the recoverable nature of the "advertising expenses" early in this docket and have modified and highlighted their processes and procedures as to those expenditures in response to Docket Nos. 12-0511/12-0512 (Consol.). The Companies submit that Staff's proposed adjustments should be rejected as they lack any sound factual basis, are contrary to the evidence, and are contrary to Sections 9-225 and 9-227.

Staff's Position

Staff maintains that the Commission should adopt Staff's rebuttal adjustment to eliminate advertising expenses that are of a promotional, goodwill or institutional nature. Staff's adjustment includes promotional or goodwill natured costs for support of events; expenditures for employee apparel and event "premiums", *e.g.*, pens, pencils, mini-flashlights and travel mugs; and expenditures to provide funding of events for charitable organizations.

Staff explains that the issue of advertising expenses that are of a promotional, goodwill or institutional nature are addressed in Section 9-225 of the Act which expressly states in part:

> In any general rate increase requested by any gas or electric utility company under the provisions of this Act, the Commission shall not consider, for the purpose of determining any rate, charge or classification of costs, any direct or indirect expenditures for promotional, political, institutional or goodwill advertising, unless the Commission finds the advertising to be in the best interest of the Consumer or authorized as provided pursuant to subsection 3 of this Section. 220 ILCS 5/9-225(2).

Section 9-225 of the Act defines goodwill or institutional advertising as:

> [A]ny advertising either on a local or national basis designed primarily to bring the utility's name before the general public in such a way as to improve the image of the utility or to promote controversial issues for the utility or the industry. 220 ILCS 5/9-225(1)(d).

Staff notes that the Commission adopted identical Staff adjustments to eliminate advertising expenses that were of a promotional, goodwill or institutional nature in the Companies' 2007, 2009 and 2011 rate cases. Docket Nos. 07-0241/07-0242 (Consol.), Order at 41; Docket Nos. 09-0166/09-0167 (Consol.), Order at 81; and Docket Nos. 11-0280/11-0281 (Consol.), Order at 47. In the Companies' 2012 rate case, Staff made an identical proposal, but the Commission did not adopt a portion of Staff's proposed adjustment that the Commission determined to qualify as charitable contributions. Docket Nos. 12-0511/12-0512 (Consol.), Order at 164.

Staff holds that the Commission should not allow the Companies to include advertising that is of a charitable nature in rates in this proceeding. In the Companies' 2012 rate case, the Commission stated the Companies must be more careful in distinguishing sponsorship and institutional expenditures that are allowable for charitable purposes and those that are allowable advertising expenses. Docket Nos. 12-0511/12-0512 (Consol.), Order at 164. In spite of the Commission's direction, the Companies have continued to record expenditures that are of a promotional, goodwill or institutional nature that might be allowable for charitable purposes as advertising expenses. If the Companies request recovery of charitable costs as advertising expenditures under the guidelines provided by Section 9-225 of the Act, the Companies should not be permitted to reclassify expenditures during the proceeding to ask for recovery under Section 9-227 of the Act as Staff (and other parties) would not have the opportunity to adequately and timely review the expenditures for compliance with Section 9-227. Staff argues that the Commission should disallow for recovery through rates determined in these proceedings the sponsorship expenditures that have been recorded as advertising that do not meet the requirements under Section 9-225 of the Act.

Further, Staff finds that allowing the Companies to file a rate case with charitable costs for Staff to review as advertising expenses, and then allowing charitable costs to be included in rates as advertising, would give no meaning to the prohibition of promotional, goodwill, and/or institutional advertising required of the Commission by Section 9-225 of the Act.

CCI's Position

CCI notes that Staff witness Mr. Kahle identified claimed advertising expenses that are of a promotional, goodwill or institutional nature and should be disallowed. Mr. Kahle identified two categories of advertising expenses for which recovery is not appropriate: i) Account 909 – costs for support of events; and ii) Account 909 – sponsorships of community events. The Companies accepted a portion of Mr. Kahle's adjustment, but did not accept the portion related to event sponsorships. CCI supports Staff's recommended disallowance.

CCI notes that the Companies claimed that their sponsorships promote awareness about special events and projects that serve the customers in communities in the Companies' service territories and should be recoverable. As Mr. Kahle noted, however, last year the Commission warned the Companies to be more careful in distinguishing sponsorship and institutional expenditures that are allowable for charitable purposes and those that are allowable advertising expenses. Docket Nos. 12-0511/12-0512 (Consol.), Order at 164. CCI explains that this is an important distinction, as Section 9-225 of the Public utilities Act expressly prohibits recovery of advertising expenses incurred for promotional, political, institutional or goodwill advertising. The legislature defined such goodwill or institutional advertising as "advertising… designed primarily to bring the utility's name before the general public in such a way as to improve the image of the utility or promote controversial issues for the utility or the industry." 220 ILCS 5/9-225(1)(d), 5/9-225(2). CCI states that the expenses at issue are not properly recovered as advertising expenses because their primary purpose is to improve the Companies' images. CCI believes that the Commission should adopt Mr. Kahle's adjustment to exclude Goodwill and Institutional Advertising from recovery.

Commission Analysis and Conclusion

The Commission agrees with the Utilities and approves the Utilities' Advertising Expenses of $4,000 for North Shore and $51,000 for Peoples Gas. Staff and CCI seek to disallow the Utilities' "advertising expenditures" that go to charitable purpose: (1) in the case of North Shore Gas: the American Legion, Children of Purpose and the University Center of Lake County and (2) in the case of Peoples Gas: the Museum of Science and Industry, the Red Moon Theater, the Hispanic Heritage Organization and others. The Commission finds that the Utilities have established that these expenditures and the organizations are charitable in nature and therefore recoverable under Section 9-227. Further, the Commission finds that the Utilities have responded to the Commission's directions in Docket Nos. 12-0511/12-0512 (Consol.) and that the Utilities have taken the necessary steps to better classify and distinguish these types of charitable expenditures from nonrecoverable "advertising expenses." The Commission notes that the rulemaking on charitable expenditures in Docket No. 12-0457 should provide further guidance in the classification and distinguishing of expenditures.

c. Institutional Events

Companies' Position

The Companies note that Staff proposes to disallow $203,000 of Peoples Gas' sponsorship of institutional events and $10,000 of North Shore's sponsorship of institutional events, on the theory that the costs are for promotional, goodwill advertising, and thus are barred from recovery under Section 9-225 of the Act. The Companies add that although CCI did not submit evidence on this issue, it supports Staff's position.

The Companies contend that they have demonstrated that their expenditures for institutional events: (1) support local charities, (2) serve as a means for the charities to raise contributions, (3) allow for dialogue between the charities and the Companies so they can better serve the community, and (4) foster cross-collaboration between the Companies and the community so the Companies can better serve their customers. The Companies argue that charitable expenditures are recoverable under Section 9-227.

The Companies claim that, contrary to Staff's argument that these institutional expenditures are recorded as institutional events and are therefore, promotional in nature and not recoverable, these institutional event expenditures support the charitable organizations' public missions and are recoverable. The Companies indicate that these expenditures support institutional events of the Chicago Police Memorial Foundation, the Adler Planetarium, the Chicago Children's Choir, the Chicago Public Library Foundation, Connections for Abused Women and their Children, Chicago Sinfonietta, the Chicago Urban League and along with other charitable institutions' events.

The Companies explain that each of the institutional events where recovery is sought has a description of the nature of the event, the charitable institution holding the event, and a description of the purpose of the expenditures. Further, the Companies assert that the same screening criteria as discussed with regards to Advertising Expenses are used to assess making the expenditure. The Companies contend that Staff makes a blanket dismissal of the expenditures labeled "institutional events", indicating they are simply promoting goodwill, where in reality, supporting these institutional events help support those charitable organizations' public missions. The Companies contend that the claim that the Companies have not shown the sponsorships are not promotional is incorrect, and, moreover, for the claim to be correct, the meaning of the term promotional would have to be stretched beyond the language and the reasonable and fair interpretation of Section 9-225.

The Companies add that Staff and CCI argue that these expenditures should not be recoverable because they put the Companies' names in a "philanthropic light" or improve the image of the Companies. The Companies agree that if the institutional expenditures were solely for promotional or goodwill advertising within Section 9-225(2), then the expenditures should not be recovered. However, the Companies note, the Commission previously has rejected the "philanthropic light" argument, which seeks to redefine funds spent on charitable purposes.

Further, the Companies contend that Staff's claim as to "misclassification" of these institutional expenditures as a means of disallowing the costs should be rejected. The Companies assert that, similar to the contested Advertising Expenses, the nature of the expenditure should determine its recoverability, not the accounting classification. The Companies explain that these institutional events: 1) support local charities; (2) serve as a means for the charities to raise contributions; (3) allow for dialogue between the charities and the Companies so they can better serve the community; and, (4) foster cross-collaboration between the Companies and the community so that the Companies can better serve their customers. The Companies emphasize that this same set of issues regarding institutional expenditures was addressed in Docket Nos. 12-0511/12-0512 (Consol.) and the Commission rejected similar Staff challenges, ruling that:

> The Companies have provided sufficient evidence to show that these contributions were made to support fundraising events for local charities and communities in the Companies' service territory and not primarily to promote the Companies or foster goodwill towards the Companies.

Docket Nos. 12-0511/12-0512 (Consol.), Order at 169.

The Companies argue that an institutional event expenditure that goes to a charitable purpose, such as fundraising for a charitable institution or community group is recoverable. The Companies add that merely because an expenditure is classified as spending for an institutional event does not lead to its disallowance. Docket Nos. 12-0511/12-0512 (Consol.), Order at 169. The Companies assert that the actual nature of the expenditure, in this case as presented by the Companies for support of charitable institutions and community groups within each Utility service territory, determines the recoverability.

To support the Companies position, the Companies note that, similar to changes in descriptions and processes as to "advertising expenditures" under Account 909, the Companies have: (1) expanded the descriptions of the nature of the institutional event,

(2) specifically identified the charitable institution holding the event and (3) have provided expanded descriptions of the purpose of the institutional event spending.

The Companies maintain that as in *Peoples Gas 2012*, the Companies have made the necessary showings, and Staff's adjustments should be rejected. The evidence shows that the costs in question are recoverable.

Staff's Position

Staff states that the Commission should not allow the Companies to recover, through rates set in this proceeding, miscellaneous general expenses for "institutional events annual fund-raising support" because the costs are either of a promotional, goodwill or institutional nature, not necessary to provide utility service to ratepayers, and are therefore barred for cost recovery under Section 9-225 of the PUA. Support of fund-raising events, while promoting good corporate citizenship, are of a promotional and goodwill nature which presents the Companies' names before the general public in a way as to improve their image. Staff maintains that these expenditures are not necessary to provide utility service and provide no direct benefit to ratepayers. The Act requires costs "designed primarily to bring the utility's name before the general public in such a way to improve the image of the utility or to promote controversial issues for the utility or the industry" to be excluded from rates. 220 ILCS 5/9-225(1)(d) and 9-225(2).

In the Companies' most recent rate cases (Docket Nos. 12-0511/12-0512 (Consol.)), Staff made an identical proposal which the Commission adopted, except for a portion that the Commission determined to qualify as charitable contributions. Staff submits that in this proceeding, however, the Commission should adopt Staff's entire adjustment for the same reasons discussed above in section C.3.b for Advertising Expenses. Staff emphasizes that expenditures which are of a promotional, goodwill or institutional nature, which are recorded as miscellaneous general expenses, should not be considered for the purpose of determining rates pursuant to Section 9-225 of the Act.

Staff continues that allowing the Companies to file a rate case with expenditures which are of a promotional, goodwill or institutional nature for Staff to review as institutional events, and then allowing promotional, goodwill or institutional costs to be included in rates as institutional events, would give no meaning to the prohibition of promotional, goodwill, and/or institutional advertising required of the Commission by Section 9-225 of the Act.

CCI's Position

CCI finds that the Commission should adopt Staff witness Mr. Kahle's adjustment to reduce the Companies' proposed test year expenses to exclude expenses incurred for institutional events that are of a promotional, goodwill or institutional nature. The expenses at issue are for tickets or tables at meals where the Companies received promotional recognition. The Companies weakly defended these expenses as being charitable in nature, but did not contest that they received public recognition, as well as tangible benefits such as food and entertainment, for their support. The Companies' intentions to support the organizations described in Mr. Moy's testimony are laudable, and the Companies can continue to give that support, even without ratepayer recovery. However, CCI asserts the benefits the Companies receive from these contributions cannot be ignored, and ratepayer recovery is not permitted for costs designed primarily to bring the utility's name in a philanthropic light or to improve the image of the utility. 220 ILCS 5/9-225(d). CCI holds that these challenged costs are not necessary for the provision of safe and adequate utility service, and they should be excluded from rates. CCI states that accepting the Companies' statements of their belief in the importance of supporting these institutions, their shareholders should be happy to fund the costs of participating in these events without recovery of such expenses in rates. CCI concludes that to protect ratepayers and to comply with the governing statutory constraints, the Commission should adopt Mr. Kahle's adjustment.

Commission Analysis and Conclusion

The Commission agrees with the Utilities and approves the Utilities' Institutional Events expenditures of $203,000 for Peoples Gas and $10,000 for North Shore. The Commission rejects Staff's proposed disallowance of $203,000 of Peoples Gas' institutional event spending and $10,000 of North Shore's institutional event spending and finds that those institutional event expenditures made by the Utilities are recoverable. The Utilities have presented sufficient evidence identifying those institutional events' spending as contributions made to support local charities and community groups and not primarily to promote the Utilities and enhance its goodwill in the community. The Commission concludes these institutional event expenditures are not barred under Section 9-225 and are recoverable under Section 9-225 and 9-227.

d. Charitable Contributions

Companies' Position

The Companies note that Staff proposes to disallow $28,000 of Peoples Gas' charitable contributions and $1,000 of North Shore's charitable contributions. The Companies state that Staff proposes to disallow those charitable contributions as those contributions are either to: (1) organizations outside of the Companies' service territory or (2) universities and colleges outside of the State of Illinois. The Companies add that Staff indicates that, for a charitable expenditure to be recovered by a utility in accordance with Section 9-227, the expenditures must be directed to charitable organizations within a utility service territory or providing some type of education benefit within a utility service territory. The Companies mention that, in support of their argument, Staff and CCI cite the Commission's decision in Docket Nos. 12-0511/12-0512 (Consol.) that held that a utility must show a charitable donation benefit customers in its service territory in order to recover those expenses. Docket Nos. 12-0511/12-0512 (Consol.), Order at 167. The Companies state that although CCI did not submit evidence on this issue, it supports Staff's position.

The Companies explain that Section 9-227 of the Act, 220 ILCS 5/9-227, expressly allows recovery of donations made by a public utility for "…the public welfare or for charitable scientific, religious, or education purposes…" as the amounts are reasonable. The Companies note that the overall reasonableness of the amounts of the charitable contributions is uncontested. Further, Section 9-227 limits the power of the Commission to establish rules disallowing charitable contributions, stating in part:

> In determining the reasonableness of such donations, the Commission may not establish, by rule, a presumption that any particular portion of an otherwise reasonable amount may not be considered as an operating expense. The Commission shall be prohibited from disallowing by rule, as an operating expense, any portion of a reasonable donation for public welfare or charitable purposes.

Nonetheless, the Companies assert that Staff seeks to maintain the requirement (in substance, a rule) disallowing charitable contributions outside a utility's service territory. The Companies state that in Docket Nos. 12-0511/12-0512 (Consol.), the Commission ruled that:

> The Commission notes that a utility is not precluded from recovering expenses for charitable contributions simply because the organization receiving the donation is outside the utility's service territory. However, the utility must show that the donation will provide a benefit to customers in its service territory to recover these expenses.

Docket Nos. 12-0511/12-0512 (Consol.), Order at 167.

Further, the Companies detail that the Commission also ruled in Docket Nos. 12-0511/12-0512 (Consol.) that charitable expenditures to colleges and universities outside of the State of Illinois were not recoverable. Docket Nos. 12-0511/12-0512 (Consol.), Order at 167. The Companies disagree with the Commission's ruling in Docket Nos. 12-0511/12-0512 (Consol.), noting that Section 9-227 does not include such a restriction. The Companies respectfully request that the Commission reconsider its approach to these contributions in light of the statutory requirements applicable to recovery of charitable contributions as an operating expense. Statutorily, restrictions on the recoverability of charitable contributions under Section 9-227 are based on: (1) the recipient of the charitable contribution - entities that provide contributions to public welfare, or scientific, religious or educational purpose and (2) whether the donations are a reasonable amount. The Companies argue that the contributions at issue meet these criteria.

The Companies state that many of the out-of-service territory contributions that are challenged by Staff are related to utility employee matching gifts where the Companies, match, dollar-for-dollar, up to a certain level gifts to charitable institutions. Many of these contributions are individually small charitable contributions that are in communities where the Companies' employees live or coincide with the educational institution that an employee attended. Further, the Companies assert that strengthening the overall network of charitable institutions in northern Illinois and surrounding areas is beneficial to the Companies' service territory in general. In addition, the Companies contend that out-of-state universities and colleges do provide graduates that work for the Companies.

The Companies add that CCI argues that charitable contributions are discretionary utility spending and not necessary for the provision of safe and reliable utility service. Further, CCI contends that charitable contributions "force" utility customers to support organizations that an individual customer may not otherwise support. The Companies argue that CCI's argument should be disregarded, as CCI's two conditions as to the "necessity" of the expenditure or the "forcing" of customer expenditure are not elements of the statutory requirement for rate recovery of a charitable expenditure and instead amount to an attempt to overrule the statute. The Companies state that the statutory requirement for recoverability of utility charitable expenditures indicated in Section 9-227 is:

> …whether a rate or other charge or classification is sufficient, donations made by a public utility for the public welfare or for charitable scientific, religious or educational purposes, provided that such donations are reasonable in amount.

220 ILCS 5/9-227.

The Companies assert that Staff and CCI ignore that Section 9-227 expressly allows recovery of donations made by a public utility for "…the public welfare or for charitable scientific, religious, or education purposes…" as the amounts are reasonable and the reasonableness of the amounts is uncontested here. The Companies contend that although particular occurrences of employee contributions may vary over time, the overall expected total level of contributions, as indicated in each Utility's C-7 filing is reasonable for the future test year of 2015. The Companies emphasize that Section 9-227 limits the power of the Commission to establish rules disallowing charitable contributions.

The Companies argue that the statutory standard for recovery of expenditures under Section 9-227 is clear, and notes that no party has argued that the particular expenditures do not go to a charitable purpose. Further, the Companies state that no party has argued that the overall amount of charitable expenditures is unreasonable. The Companies contend that Staff's position is contrary to Section 9-227 both in terms of its provisions regarding what is recoverable and in terms of its provisions limiting disallowance by rule. The Companies assert that the charitable organizations where Staff is seeking a disallowance of expenditures are all entities that provide contributions to public welfare, or scientific, religious or educational purpose. The Companies note that these charitable organizations include, for example, food banks and a wide range of educational institutions. The Companies hold that as these organizations contribute to the public welfare, or scientific, religious or educational purpose and the specific level of expenditures are not argued as unreasonable, these expenditures should be recoverable. The Companies argue that the Staff position proposes a ruling that would be unlawful and should be rejected. However, the Companies assert that even if Staff's position could be lawful, the evidence here supports recovery.

<u>Staff's Position</u>

Staff maintains that the Commission should adopt Staff's rebuttal adjustment to reduce test year expenses for charitable contributions for which there is no tangible evidence of benefit to ratepayers in the Companies' service territory. Staff's adjustment eliminates contributions made to organizations outside the Companies' service territory and colleges and universities outside of the State.

Staff notes that in the Companies' most recent rate case, the Commission accepted the portion of Staff's proposed adjustments to disallow contributions made to organizations outside the Companies' service territory and to colleges and universities outside of the State of Illinois. Docket Nos. 12-0511/12-0512 (Consol.), Order at 166-167.

CCI's Position

CCI supports Staff witness Kahle's adjustment to the Companies' contributions to universities outside Illinois and to other organizations outside the Companies' service territories. Contributions for charitable and other statutorily permitted purposes are a discretionary expense not necessary for the provision of safe and reliable service. CCI states that these contributions essentially force all of a utility's ratepayers to support organizations chosen by utility management, even if the goals and objectives of those organizations conflict with those of individual ratepayers.

CCI explains that though Section 9-227 of the PUA allows recovery of reasonable contributions, the Commission has noted that, in order for a contribution to an organization outside of a utility's service territory to be recoverable, the utility must show that the donation will provide a benefit to customers in its service territory. Docket Nos. 12-0511/12-0512 (Consol.), Order at 164. Additionally, the Commission has voiced its concern that, particularly in the current economic climate, "every dollar will make a difference" to ratepayers. Accordingly, the Commission concluded that claimed charitable contributions must be closely examined. *Ameren Illinois Co. d/b/a Ameren Illinois*, Docket No. 11-0282, Order at 31 (January 10, 2012).

CCI finds that while the Companies are free to continue making contributions to any organizations they choose, the Commission should, as it has in the past, limit recovery of those contributions to those that benefit the Companies' ratepayers. CCI submits that Mr. Kahle's adjustment is reasonable and should be adopted by the Commission.

Commission Analysis and Conclusion

The Commission agrees with Staff and CCI and finds that the charitable contributions made by the Utilities related to matching the Utilities' employee gifts to out-of-state universities and colleges are not recoverable. Staff's adjustment eliminates contributions made to organizations outside the Companies' service territory and colleges and universities outside of the State. Staff's adjustment comports with numerous past Commission rulings on the recovery of the Companies' charitable contributions for which there is no tangible evidence of benefit to ratepayers in the Companies' service territory.

e. Social and Service Club Membership Dues

Companies' Position

The Companies note that Staff proposes to disallow \$44,000 of Peoples Gas' social and service club membership dues and \$17,000 of North Shore's social and service club membership dues. The Companies note that although CCI did not submit evidence on this issue, it supports Staff's position. The Companies state that Staff proposes to disallow those social and service club membership dues by arguing that they are a promotional and goodwill practice and not necessary in providing utility service. The Companies offer that Staff references Peoples Gas' direct coordination with the City of Chicago Aldermanic offices and the City's Department of Water Management in its ongoing AMRP project as a reason the "indirect" contacts and related expenditures for social and service clubs should not be included in the test year. In addition, Staff asserts that certain portions of these dues are lobbying expenses, and therefore not recoverable. The Companies contend that Staff is incorrect that the expenses are not appropriate and support utility service to customers.

The Companies argue that their expenditures on social and service clubs provide benefits to customers in an indirect way by allowing the Companies to work with various external stakeholders within their service territories. The Companies assert that the membership in these social and service clubs allow the Companies to interact with other business and governmental entities to develop contacts, exchange ideas, coordinate current projects and plan future projects. Further, the Companies submit that these memberships provide important interactions with other business and governmental entities within the Companies' service territories. The Companies hold that they provide, maintain and continue to develop vital infrastructure within their service territories.

The Companies note that while the City of Chicago Aldermanic offices and the City's Department of Water Management are key stakeholders where Peoples Gas has direct, routine and beneficial interactions, there are more stakeholders than just those groups. The Companies explain that the social and service club memberships expose the Companies to a wider group of parties with wider interests from across the Companies' service territories, and that social and service club memberships can provide opportunities for broader interactions that allow for better coordination, identification of issues, and can help improve the Companies' service to its customers.

The Companies state that Staff and CCI argue that certain of these social and service club membership expenditures are not necessary for utility service. The Companies disagree with this as a ground for disallowance. The Companies contend that these expenditures for social and service club memberships enhance the ability of the Companies' personnel to interact with stakeholders in the Companies' service territories and help identify challenges, risks, and opportunities to improve the Companies' services to its customers. The Companies further note that Staff argues that certain of these expenditures are unnecessary, as the Companies already have direct contacts with stakeholders in the Companies' service territories. The Companies contend that although they have direct contacts with a variety of stakeholders in the Companies' service territories, the advantage that the social and service club memberships bring is the ability to interact with a wider group of business and governmental entities. The Companies submit that Staff's argument that the Companies' expenditures for social and service clubs memberships provide no customer benefit should be rejected.

<u>Staff's Position</u>

Staff argues that the Commission should adopt Staff's rebuttal adjustments to remove social and service club membership dues which are promotional or goodwill in nature. While these social and service club membership dues may promote good corporate citizenship, they are not necessary in providing utility service. Staff asserts that ratepayers should not be burdened with the expense of the Companies participating in these organizations, and these nonessential expenses should be removed from the Companies' test year operating expenses.

Staff submits that in the Companies' 2007, 2009, 2011 and 2012 rate cases the Commission accepted Staff's proposed adjustments to remove certain social and service club membership dues. Docket Nos. 07-0241/07-0242 (Consol.), Order at 41-42; Docket Nos. 09-0166/09-0167 (Consol.), Order at 41; Docket Nos. 11-0280/11-0281 (Consol.), Order at 46; and Docket Nos. 12-0511/12-0512 (Consol.), Order at 119.

CCI's Position

CCI argues that the Commission should adopt Staff witness Mr. Kahle's adjustment to remove certain social and service club dues that are promotional and goodwill practice in nature. CCI states that participation in these organizations is not necessary for the provision of safe and reliable service.

CCI explains that in the past the Companies have accepted Staff's adjustment to social and service club dues. Docket Nos. 12-0511/12-0512 (Consol.), Order at 119; Docket Nos. 11-0280/11-0281 (Consol.), Order at 46; Docket Nos. 09-0166/09-0167 (Consol.), Order at 41; Docket Nos. 07-0241/07-0242 (Consol.), Order at 42. However, in this case, the Companies continue to seek recovery for these costs, arguing that the networking opportunities and exchange of ideas afforded by participation in social and service clubs facilitates interactions with businesses and municipalities who are affected by the Companies' construction programs.

CCI notes that the Companies assert that all of their social and service club membership dues are recoverable costs. CCI argues that with regard to the provision of regulated services the Companies already provide direct channels of communication with the businesses and municipalities that are members of such organizations. Moreover, according to the Companies, each utility establishes and uses its organization's customer service and planning department. Such organizational mechanisms for interacting with customers and governmental agencies are already in place, and they are paid for by ratepayers.

CCI claims that networking is simply not a recoverable cost of providing service under the PUA, nor should it be. If the Companies continue to find merit in the networking opportunities afforded by participating in these social and service clubs, then their shareholders should bear those costs. CCI submits that the Commission should adopt Mr. Kahle's reasonable adjustment.

Commission Analysis and Conclusion

The Commission agrees with Staff and CCI and adopts Staff's proposed disallowance of social and service club membership dues in the amount of $44,000 for Peoples Gas and $17,000 for North Shore. The Utilities claim that these expenditures provide benefits to customers in an indirect way by allowing the Companies to interact with other business and governmental entities to develop contacts, exchange ideas, coordinate current projects, maintain and continue to develop infrastructure within its service territories. The Commission disagrees and finds that these expenditures are not recoverable.

4. Amortization Period for Rate Case Expenses

Companies' Position

The Companies note that Staff proposes to change the amortization period for rate case expenses from two years to two and one-half years, based on the premise that the Commission, if it approves the proposed WEC-Integrys transaction in Docket No. 14-0496, may approve a condition proposed there by the joint applicants regarding when the Companies' next new rates may go into effect.

The Companies state that Staff's proposal is too speculative to adopt, because it assumes approval in that Docket of both the proposed reorganization and that specific proposed condition, as well as approval of the transaction by the applicable out of state regulatory authorities.

The Companies' contend that their proposal to amortize rate case expenses over two years should be adopted. The two year amortization period is based on what the Companies have experienced in their most recent rate cases. Furthermore, the two year period is the same period approved in the Companies' 2012 rate cases. Docket Nos. 12-0511/12-0512 (Consol.), Order at 170, 175.

Staff's Position

Staff argues that the Commission should take administrative notice of the Companies' filing in Docket No. 14-0496 and amortize rate case costs over a period of two and one-half years. Staff states that in their merger filing the Companies committed that any further requests to change base rates would become effective no earlier than two years after the reorganization transaction closes and that the base rates resulting from the instant proceeding would remain "…unchanged for two and a half years or so after they are approved by the Commission." Staff adds that new rates in the instant proceeding would go into effect on or before February 1, 2015 and that the reorganization transaction will not close until July 2015 at the earliest. According to Staff, a July 2015 closing means that the Companies' next base rates would go into effect no earlier than July 2017, that is, two and a half years from when a Commission order is issued in the instant proceeding.

Staff acknowledges that while the outcome of the merger case is unknown, Staff cannot recall a merger petition which was denied. Staff asserts that the Commission should consider the history of merger approvals and adopt two and one-half years as the minimum period for which base rates resulting from the instant proceeding will be in effect.

CCI's Position

CCI submits that Mr. Kahle's proposal to amortize rate case expense over two and a half years, as opposed to the two years proposed by the Companies, is imminently reasonable given the Companies' own proposal that, after the instant case, new rates will not go into effect any earlier than July 2017. The Companies have made that commitment in the pending reorganization case filed by the Companies (and other joint applicants), should the reorganization be approved. CCI continues that while it cannot be known for certain whether the reorganization will be approved, the Commission must set just and reasonable rates in this proceeding based on the evidence in this record. CCI maintains that evidence suggests that it is possible, if not likely, that new rates will not take affect for at least two and a half years and the Companies have presented no evidence to propose that new rates will be effective any earlier.

CCI adds that with approval of PGL's Rider QIP tariff, the Companies are no longer subject to the substitute natural gas ("SNG") related requirement for biennial filings. 220 ILCS 5/9-220.3(h). In the past, in the absence of a time-specific filing requirement, the Companies have delayed filing a new case for more than a decade (between Docket Nos. 95-0031/95-0032 and Docket Nos. 07-0241/07-0242). CCI states that here the Companies have simply made a bald assertion that a two-year amortization period should be approved. Given the evidence that has been presented on this issue, Mr. Kahle's proposed amortization period is the most reasonable and should be adopted; the short amortization period proposed by the Companies is unsupported, presents a distinct possibility of over-recovery, and should be rejected.

Commission Analysis and Conclusion

The Commission agrees with Staff and CCI and adopts two and a half years as the amortization period for rate case costs. Although a two-year rate case amortization period was just approved in the Utilities' last rate case in 2012, the Commission is reluctant to grant the same two-year period pending the outcome of ICC Docket No. 14-0496. Two and a half years is the earliest the Utilities may file another rate case if their merger request in the aforementioned docket is approved. The Utilities' proposal for a two-year amortization period would allow them to over-recover rate case expense, if the proposed reorganization is approved. Based on the Utilities' stated objectives and proposal, as noted in the merger docket, as well as the likelihood that the merger will occur, the minimum amortization period that is appropriate is two-and-a-half years.

5. Peer Group Analyses

AG's Position

The AG sponsored the peer group analyses of economist Dr. David E. Dismukes, Ph.D., who is the Director of the Center for Energy Studies and a Professor at Louisiana State University. Mr. Dismukes prepared a peer group comparison of the Companies' O&M and A&G costs, relative to that of 17 other Midwestern natural gas local distribution companies ("LDCs") that all have at least 50,000 customers. Mr. Dismukes used historical expense data from each utility company's state regulatory commission filing for each of the ten years 2004 through 2013. The AG explains that the purpose of this peer group comparison is to provide regulators with an objective, empirical measure of a utility's prior and current cost performance relative to other comparable Companies. Mr. Dismukes standardized expense data relative, first, to number of customers, and second, to volume of throughput, is a standard method in peer group analyses of utility cost performance.

The AG submits that Mr. Dismukes found that North Shore's O&M costs per customer in the most recent year, 2013, are estimated to be 13 percent higher than the peer group average and 191 percent higher than the "best performing company" in the sample, where the "best performing company" is defined as the one with the absolute lowest unit cost in each year over the past decade. North Shore's O&M expenses per customer have increased relative to the regional utility average over time. North Shore's A&G costs per customer in the most recent year (2013) are estimated to be 125 percent higher than the peer average and 1,232 percent higher than the "best performing company" in the sample. North Shore's A&G costs per customer experienced significant growth between the 2007-2010 time period, growing at an annual average rate of about 15.2 percent.

The AG notes that switching the focus to costs per volume, North Shore continues to look inefficient. In 2013, North Shore is estimated to have O&M costs that are 15 percent above the regional peer average, and 181 percent higher than the best performing utility included in the peer group. In 2013, North Shore Gas's A&G costs per Mcf were 120 percent higher than the peer average and were orders of magnitude higher than the best-performing company in the peer group. North Shore's trend in A&G cost per Mcf was a significantly higher growth rate than the peer group from 2007-2010.

The AG states that in summary Mr. Dismukes found that North Shore has current A&G costs (normalized either per customer or per volume) that are beyond a reasonable range, which he defined based on his expertise to mean within two standard deviations from the peer group average.

Mr. Dismukes also found that Peoples Gas' O&M costs per customer in 2013 are estimated to be 140 percent higher than the peer average and 520 percent higher than the best performing company in the sample. Peoples Gas consistently shows higher-than-average O&M costs per customer that are also growing at a much faster rate (an average of 9.7% annually since 2008) than any of the other Companies in the regional peer group (3.4% annually since 2008 on average). Peoples Gas' A&G costs per customer in 2013 are estimated to be 155 percent higher than the peer average and 1,407 percent higher than the best performing company in the sample. While Peoples Gas has seen relatively flat to decreasing A&G cost-per-customer trends since 2005, these costs have been and continue to be considerably higher than the regional peer group average.

The AG continues that normalized per volume, Peoples Gas' costs look even worse. Peoples Gas is estimated to have 2013 O&M costs per Mcf that were 164 percent higher than the regional peer average and 543 percent higher than the best-performing regional peer utility for that year. Considering Peoples Gas' trend over time, its O&M cost per volume is clearly growing at a much faster rate than O&M cost per volume in the peer group. In 2013, Peoples Gas's A&G costs per Mcf were 167 percent higher than the peer average and were orders of magnitude higher than the best-performing company in the peer group. PGL's trend in A&G cost per Mcf was relatively flat over time, even while its absolute levels of costs were significantly higher than the peer companies.

The AG states that Mr. Dismukes found that Peoples Gas has current O&M costs (whether normalized per customer or per volume) that are well beyond the "reasonable range" (defined statistically as described above for North Shore) compared to the peer group average. Mr. Dismukes also found that Peoples Gas has current A&G costs (per customer or per volume) that are beyond the "reasonable" statistical boundary.

The AG argues that the only witness from North Shore or Peoples Gas to address Mr. Dismukes's findings was NS/PGL witness Mr. Dennis M. Derricks. In rebuttal testimony, Mr. Derricks suggested that the 17 other Companies included in Mr. Dismukes's peer group should not be treated as "peers" (despite that they are also in the Midwest Census Region and serve at least 50,000 customers) because Mr. Dismukes did not show that the other companies have comparable service territories, comparable systems, comparable sizes, and comparable state and local regulations.

Mr. Derricks also pointed to the fact that some of the companies in the peer group are combined gas and electric Companies. In surrebuttal testimony, Mr. Derricks similarly suggested that Mr. Dismukes's rebuttal analyses do not provide information that the Companies in the alternative 'peer groups' have comparable service territories (including having comparable customer bases over time), comparable systems, and comparable state and local regulations. He also argued that none of the Companies in Mr. Dismukes's rebuttal peer group analysis include only an urban area like Peoples Gas. He added that Mr. Dismukes did not provide information as to the peer Companies' (1) accounting policies regarding expensing versus capitalization, (2) gas distribution system characteristics, or (3) applicable state and local regulations. Finally, Mr. Derricks argued that Mr. Dismukes has not normalized the delivery data in his cost-per-volumes analyses.

The AG notes that Mr. Derricks did not explain why an all-urban area like PGL's service territory might necessarily, for that reason, have higher operating expenses. Mr. Derricks did not explain how state and local regulations applicable to Peoples Gas or North Shore might drive up operating expenses relative to the effect of state and local regulations in other jurisdictions. He did not make any attempt to explain how Peoples Gas or North Shore might significantly differ in their accounting policies or gas distribution system characteristics from the other peer companies or how any such differences could drive differences in operating expenses. The AG continues that while anything is certainly possible, Mr. Derricks made no attempt to show how any of the Companies' immutable characteristics are likely to make them outliers in normalized spending with respect to the peer group.

The AG asserts that to address some of Mr. Derricks's objections, Mr. Dismukes repeated his analysis with two alternative peer groups: first, a group of nine other LDCs in the Midwest and/or Northeast census regions that serve large metropolitan areas with populations of at least two million; and second, a group of 17 other LDCs in the Midwest and/or Northeast census regions that serve at least 250,000 customers and reported at least 10 percent high priority mains, for at least five years over the past decade. Mr. Dismukes's analysis with the large metropolitan area peer group did not significantly alter his findings with respect to PGL's unreasonably high O&M cost position or the historical trends thereof. He did find, though, that PGL's A&G costs were only 23% higher than the peer average per customer and only 27% higher than the peer average per Mcf, down from 155% and 167% higher in the original analysis.

The AG explains that Mr. Dismukes's analysis with the high priority mains peer group showed that Peoples Gas' O&M cost-per-customer performance was competitive with the large utility high priority mains peer group average during the period spanning 2003 to 2006. He found that People's O&M cost performance has deteriorated since 2006, relative to the other large Companies that have high shares of leak-prone pipes. By 2012, PGL's O&M cost performance per customer was 64 percent above the high-priority mains peer average, and 226 percent above the best-performing company in the group. Per Mcf, the Peoples Gas O&M cost performance was initially better than the peer group average until 2007, at which time its O&M costs per Mcf performance began to deteriorate relative to the high-priority-main peer group. Since 2007, Peoples Gas' O&M costs per Mcf rank 14th and 16th out of 18 companies in the group.

The AG states that looking at PGL's A&G costs relative to the high-priority main peer group, Mr. Dismukes found that the Company's A&G costs per customer averaged over 75 percent higher than the peer average for the past decade and around 20 percent higher in 2012. Peoples Gas' 2012 A&G costs per customer were also about 580 percent higher than the best performing company in the sample. Normalized by volume, PGL's A&G cost performance was 21 percent higher than the high-priority sample average and 740 percent higher than the best performing peer utility in the sample. Peoples Gas' A&G cost-per-volume trends over time are comparable to those discussed in Mr. Dismukes's direct testimony analyses.

In conclusion, the AG states that whether looking at his original peer group sample or focusing on peer groups that might arguably, under the most charitable interpretations of PGL's objections, be more appropriately selected for comparison with Peoples Gas, Mr. Dismukes still found that Peoples Gas is a high-cost utility. Mr. Dismukes recommended that, in light of the higher-than-reasonable O&M and A&G expense levels he found to be endemic at North Shore and Peoples Gas, the Commission should accept the O&M and A&G expense recommendations offered by Mr. Effron. Mr. Dismukes argued that his analysis shows that there are likely considerable accumulated inefficiencies embedded in the Companies' test-year projections that need to be eliminated. He further argued that Mr. Effron's proposed reductions to test-year operating expense at both Companies would assist in bringing the Companies' costs more in line with the 'reasonable range' by reducing the discrepancies between the Companies and their peers.

The AG notes that Mr. Derricks observed several times in his testimony that Mr. Dismukes did not propose specific line-item adjustments to the Companies' test-year expenditures. The AG submits that Mr. Dismukes's explanation for the appropriate use of his findings speaks for itself. While the AG presented statistical analysis by Mr. Dismukes showing the inefficiency of NS and PGL, the AG maintains that it also presented compelling personal testimony of PGL customers who experienced firsthand the Company's inefficiency. The AG submits that Mr. Dismukes's findings, together with the wastefully inefficient service experienced by the Peoples Gas' two consumer witnesses, provide further support for the proposed adjustments to operating expenses made by Mr. Effron.

Companies' Position

The Companies state that, ostensibly in support of AG witness Mr. Effron's proposed adjustments to O&M and A&G expenses, AG witness Dr. Dismukes presented what he claimed are “peer” group analysis of the Companies’ O&M and A&G expenses. The Companies note that neither Dr. Dismukes nor Mr. Effron tied the “peer” group analysis to any of Mr. Effron’s specific proposed adjustments. Further, Dr. Dismukes did not himself propose any adjustments. The Companies maintain that his analyses are incomplete and they are not a reliable basis of support for any of Mr. Effron’s O&M and A&G expense adjustments, for numerous reasons.

The Companies submit that when Mr. Effron’s specific adjustments to O&M and A&G expenses are considered, it is clear that they rely on specific points about the Companies, *i.e.*, their test year employee levels, increases in medical benefits expenses, and the challenged IBS cost items. However, Dr. Dismukes’ testimony simply does not address those items in any direct or meaningful way.

The Companies state that the AG acknowledges that Dr. Dismukes did not propose any specific adjustments, but the AG claims that his analyses nonetheless support Mr. Effron’s proposed O&M and A&G expenses adjustments. The AG, like Dr. Dismukes, makes no attempt to explain how the analyses tie to any of those specific adjustments. For example, the AG does not explain how assertions that the Companies’ costs are high compared to their “peers” somehow supports the hypothesis that the Companies will have fewer employees in 2015 than they have forecasted, or that the independent actuary overestimated the increases in medical benefits costs in 2015.

The Companies also mention that Dr. Dismukes’ analyses expressly are limited to O&M and A&G expenses. They do not take into account overall costs of service, because they do not include any of the categories of customer expense or the return of and on plant and other capital investments. The Companies state that he presented no comparison of overall costs of service of the Companies versus other companies.

As well, the Companies find Dr. Dismukes’ analyses look at data from 2004 to 2013, but the test year in the current cases is 2015. Moreover, he never addresses the fact that the Commission reviewed the Companies’ costs of services in their 2007, 2009, 2011, and 2012 rate cases.

The Companies continue that Dr. Dismukes failed to show to any reasonable degree that the “peers” are peers of the Companies for cost comparison purposes in the current cases. He did not show, among other things, that they have comparable service territories (including whether they have comparable customer bases over time), comparable systems (such as the prevalence of inside or outside metering), or comparable state and local regulations under which they operate. Many of the “peers” are combined gas and electric companies (which could result in common cost being reduced), none is an essentially all urban utility like Peoples Gas, and he did not examine the state and local regulations under which the “peers” operate. Regulations matter, as has been discussed with respect to restoration expenses, for example. He also did not show that they have comparable accounting policies such as for when expenses are capitalized or accounting for service company expenses. The Companies state as well that he did not look at whether any of the “peers” had a rate freeze or other rate increase prohibition in place during the period he studied.

The Companies note that the AG attempts to defend the contention that the "peer" companies are in fact peers, however the AG's arguments fail. Dr. Dismukes should be expected to show that the "peer" Companies are in fact peers, and the AG fails to refute Mr. Derricks' criticisms. For example, the AG claims that Mr. Derricks did not show that it matters that Peoples Gas has an all urban service territory unlike all of the "peers" nor how state and local regulations might drive up operating expenses. The Companies state that is not correct. As Mr. Derricks pointed out, regulations matter, as has been discussed with respect to the City of Chicago's regulations and restoration expenses. The Companies note that in the instant cases, the Companies' direct testimony supported a forecasted $16,780,000 increase as of 2015 in Peoples Gas' distribution expenses compared to the 2012 level due primarily to changes in Chicago Department of Transportation Regulations that went into effect in the second half of 2012 or 2013, and further changes that became effective in 2014. The Companies maintain that this increase is uncontested. Additionally, in surrebuttal the Companies pointed out that paving costs (which reflect regulatory requirements) are running nearly $8 million over the forecast as of August 2014, an increase that was not reflected in Peoples Gas' proposed revenue requirement. In the Companies' 2007 rate cases, the Commission approved (with modifications) updated rebuttal amounts for Peoples Gas' resurfacing costs in the City of Chicago. Docket Nos. 07-0241/07-0242, Order at 40. Also with respect to whether the peers have similar accounting policies, or gas distribution systems, the AG tries to reverse the burden of proof, by claiming that the Companies have to disprove that the "peers" are comparable to the Companies, rather than Dr. Dismukes having to show they are comparable in the first place.

The Companies submit that a significant part of Dr. Dismukes' analyses is based on costs per volume of gas delivered, but he did not explain how that is a relevant or meaningful criterion, and he has not normalized that delivery data. The AG's Initial Brief suggests that looking at costs per volume is a standard method, but the AG does not deny that Dr. Dismukes did not normalize the delivery data. Finally, the Companies contend that Dr. Dismukes did not identify any specific expense of either utility that he claims is imprudent, inefficient, or excessive.

The Companies note that the AG questions Mr. Derrick's qualifications as a statistician, and notes that he has not published papers or taught courses on peer group analysis, and that the development of the Companies' operational budgets is not his responsibility area. However, Mr. Derricks has an engineering degree, an MBA, and 23 years of experience working for companies. He is not an academic, so his not publishing papers or teaching courses is not an indictment. The AG does not explain how his not being one of the employees tasked with developing operational budgets undercuts his criticisms, and the AG has been unable to refute those criticisms.

The Companies continue that the AG discusses at great length the individual complaints of two Peoples Gas customers. The treatment of each and every customer matters, but the AG never shows that discussing the circumstances of two customers bears in any meaningful way on the issues in these rate cases. Neither customer has filed a complaint with the Commission.

Commission Analysis and Conclusion

The Commission agrees with the Utilities and finds that the Peer Group analyses conducted by Dr. Dismukes do not provide reliable support for the O&M and A&G expense adjustments proposed by the AG. The Commission further agrees with the Utilities and finds that Dr. Dismukes' analyses are not tied to any of AG witness Mr. Effron's specific proposed adjustments and do not bear on his specific proposals. Dr. Dismukes also did not identify specific expenses of the Utilities that are imprudent, inefficient, or excessive. As well, there are questions about whether the peers identified in the analyses are actually peers of the Utilities. The Commission finds that the analyses conducted by Dr. Dismukes do not provide independent support for the O&M and A&G expense adjustments proposed by the AG.

VI. RATE OF RETURN

A. Overview

Companies' Position

Each of the Companies propose modest increases in their overall rates of return on rate base. Peoples Gas proposes an increase from 6.67% to 7.21% based on a capital structure comprised of 50.33% common equity at a cost (a rate of return on common equity or "ROE") of 10.25%, 46.51% long-term debt at a cost of 4.32%, and 3.16% short-term debt at a cost of 1.19%. North Shore proposes an increase from 6.72% to 6.89% based on a capital structure comprised of 50.48% common equity at a ROE of 10.25%, 38.94% long-term debt at a cost of 4.13%, and 10.58% short-term debt at a cost of 1.06%. NS-PGL IB at 94-95.

Only Staff and CCI have addressed directly the Companies' cost of capital arguments. The Companies' capital structures are not disputed. The Companies and Staff are in agreement on North Shore's long-term debt costs. The Companies and Staff disagree, however, on the Companies' short-term debt costs and Peoples Gas' long-term debt costs. Staff proposes substantially lower rates of return on rate base, 6.54% for Peoples Gas and 6.23% for North Shore, by virtue of its proposal to reduce the Companies' ROE from 9.28% to 9.00%. CCI proposes a slightly smaller reduction in the Companies' ROE – from 9.28% to 9.15%. (CCI did not address short-term or long-term debt costs in its briefs.) NS-PGL IB at 105.

The legal standards governing a public utility's entitlement to a fair and reasonable return on its investment are well established and familiar. The Commission summarized these standards in one of the Companies' recent rate cases thus:

> A public utility has a constitutional right to a return that is 'reasonably sufficient to assure confidence in the financial soundness of the utility and adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.' The authorized return on equity 'should be commensurate with returns on investments in other enterprises having corresponding risks. That return, however,

> should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.'

Docket Nos. 09-0166/09-0167 (Consol.), Order at 89-90 (citations omitted). Accord Docket Nos. 12-0511/12-0512 (Consol.), Order at 181-182.

Staff's Position

Staff submitted the testimony of Ms. Janis Freetly regarding the Companies' cost of common equity, capital structures, and overall weighted average costs of capital ("WACC"). Staff agreed with North Shore's proposed embedded cost of long-term debt of 4.13%. Staff contested the cost of long-term debt for Peoples Gas, and proposed a 4.26% embedded cost of long-term debt. Staff also contested both Companies' costs of short-term debt and costs of common equity. Staff proposed a 0.74% cost of short-term debt for North Shore and 0.91% for Peoples Gas. Staff's estimate of the rate of return on common equity for both Peoples Gas and North Shore is 9.05%.

CCI's Position

Though disputes remain regarding the Companies' cost of debt, the principal cause of the Companies' excessive proposed rate of return is a result-oriented approach exemplified in the flawed cost of common equity estimate presented by the Companies' witness Paul Moul. *See* NS-PGL Ex. 34.0 (Gast) at 3:43-5:99 (cost of debt) and generally PGL Ex. 3.0 (Moul), NS-PGL Ex. 9.0 (Moul), NS-PGL Ex. 35.0 (Moul) (*re* cost of equity).

B. Capital Structure

Companies' Position

As shown in their respective cost of capital schedules, the Companies and Staff agree on the following capital structures. NS-PGL Exs. 18.1N & 18.1P; Staff Ex. 8.01. No party disputed these structures.

	Peoples Gas	**North Shore**
Common Equity	50.33%	50.48%
Long-Term Debt	46.51%	38.94%
Short-Term Debt	3.16%	10.58%

According to the Companies, these structures are similar to their currently authorized ones. Docket Nos. 12-0511/12-0512 (Consol.), Order at 182. According to Staff, these structures "reasonably balance the cost advantage of tax deductible interest expense that comes from employing debt as a source of capital against the financial strength needed to raise capital under most capital market conditions that comes from employing common equity as a source of capital." Staff Ex. 3.0 at 3-4; Staff Ex. 8.0 at 2.

Staff's Position

Staff accepted the Companies' proposed capital structures. Staff IB at 43; NS-PGL IB at 95-96.

Commission Analysis and Conclusion

The Commission finds that the Companies uncontested capital structure is supported by the evidence and is hereby adopted.

C. Cost of Short-Term Debt

Companies' Position

The Companies estimate their 2015 costs of short-term debt to be 1.06% for North Shore and 1.19% for Peoples Gas based on forecasts published by the credit rating agency *Moody's*. NS-PGL Ex. 18.0 at 4 (table); NS-PGL Exs. 18.2N & 18.2P. The Companies argue that the credit rating agency interest rate forecasts the Companies relied on to estimate their costs in 2015 are verifiable and unbiased, and that these types of forecasts are "used by investors to formulate their expectations for the future." NS-PGL Ex. 35.0 at 2. The Companies state that such forecasts are an eminently reasonable basis to predict their costs in the future. NS-PGL IB at 96.

The Companies argue that Staff's proposed short-term debt costs should be rejected because they are based on historical "spot day" measurements to forecast capital costs in a future test year, which is arbitrary and unreliable. *Id.* The Companies point out that Staff itself recognized that relying on historical data "will necessarily be arbitrary" because the analyst must choose the historical timeframe for the data. *See* Staff Ex. 3.0 at 28. Basing a forecast on historical data will produce the "correct" result only by chance. *Id.* at 28. Recognizing that spot data "is exposed to inefficiencies from a number of sources" on any given day, the Commission has asked to be informed of "the conditions or financial climate of the spot day and whether any of these might cause material market inefficiencies." Docket Nos. 09-0166/09-0167 (Consol.), Order at 125-126. Staff did not attempt to make this showing with respect to its spot day interest rate measurements.

The Companies dispute Staff's positions that "current" interest rates are better predictors of future interest rates than published forecasts like *Moody's*, and that it is impossible to forecast interest rates because such forecasts are too often "inaccurate." *See* Staff Ex. 3.0 at 4; Staff Ex. 8.0 at 4. The Companies argue that the fallacy of Staff's position is that the accuracy of forecasts can be determined only with hindsight. A forecast represents the best estimate by the forecaster with the information then available. The fact that intervening events cause future rates to differ from a forecast does not render the forecast inaccurate when it was made. The Companies explain that nothing that depends on future events can be forecasted "with certainty" because no one can know "with certainty" what the future events will be, but this does not mean that forecasts are not accurate based on the information available when they are made. NS PGL IB at 97.

The Companies argue further that all Staff's "random walk" theory proves is that on any given day, it is impossible to know whether intervening events will cause a forecast to be wrong on the high side or the low side or by how much. If a forecast's performance in hindsight is truly random, as Staff claims, then there is no reason to believe that today's forecasts are either too low or too high. What is important is the forecast's credibility and objectivity. *Id.* at 98.

The Companies point out that Staff did not challenge the credibility or objectivity of the *Moody's* short-term debt forecasts on which the Companies relied. PGL Ex. 20.0 at 9. Staff instead points to variance in the forecasts of 10-year Treasury yields for the fourth quarter of this year as evidence that interest rate forecasting is not reliable. Staff Ex. 8.0 at 5-6. The Companies state that Staff's evidence does not prove its conclusion. Rather, the variation is a product of Staff's arbitrary selection of forecasts, namely "the most easily obtainable sources Staff was able to access in the limited time available." *Id.* at 5 n.4. The fact that two of the four forecasts Staff selected were significantly different than the other two suggests that more inquiry was required to determine the reliability of the outliers. Had it engaged in that inquiry, the Companies argue that Staff could have determined whether the *Forecasts.org* and *EconomicOutlookgroup.com* forecasts (2.28% and 3.50%, respectively) were reliable, as compared to the Freddie Mac and *Survey of Professional Forecasters ("Survey")* forecasts (2.60% and 2.80%, respectively). NS-PGL IB at 98.

Finally, the Companies argue that Staff's objection to the use of interest rate forecasts for debt costs in a future test year is flatly inconsistent with Staff's reliance on forecasts in its cost of equity analyses, including (1) the "expected" quarterly dividends of the proxy group of delivery Companies used in its DCF model (Staff Ex. 3.0 at 10-11 & Sched. 3.04); and (2) gross domestic product ("GDP") inflation and GDP growth forecasts from the Energy Information Administration ("EIA"), Global Insight and the Survey *(Id.* at 16) used in its CAPM model. Forecasts from credible and objective sources are reliable for the purpose of establishing a utility's cost of capital in a future test year. NS-PGL IB at 98-99.

The Companies thus maintain that the record strongly supports basing the Companies' short-term debt costs on *Moody's* forecasts instead of a short-term debt rate selected by Staff on a single data several months ago.

Staff's Position

According to Staff, the cost of short-term debt is 0.74% for North Shore and 0.91% for Peoples Gas. Staff Ex. 8.0, 2-3, Sch. 8.01. The interest rate on short-term debt for both North Shore and Peoples Gas is based on commercial paper rates at the time of borrowing. To estimate the Companies' cost of short-term debt, Staff started with the June 12, 2014, 0.24% annual yield on 30-day A2/P2 nonfinancial commercial paper. (Staff Ex. 3.0, 5.) Then, Staff added the annual percentage cost of bank commitment fees to the annual commercial paper yield. Staff divided the amount in fees by the updated average 2015 balance of short-term debt projected to be outstanding to derive the commitment fees in percentage terms. For North Shore, adding the resulting 50 basis points to the 0.24% commercial paper yield produces a cost of short-term debt of 0.74% (0.24% + 0.50% = 0.74%). (Staff Ex. 8.0, 2-3.) For Peoples Gas, adding the resulting 67 basis points to the 0.24% commercial paper yield produces a cost of short-term debt for Peoples Gas of 0.91%.

The Companies' calculation for North Shore is 1.06% and for Peoples it is 1.19%. The parties agree that the Companies relied on forecasted commercial paper rates to estimate the cost of short-term debt for each of the Companies. Staff states that the Companies' interest rate forecasts have not been accurate. For example, in its 2011 rate cases, the Companies forecasted that the 30-day A-2/P-2 commercial paper rate would average 1.95% in 2012. In contrast, the 30-day A-2/P-2 commercial paper rate averaged 0.46% that year, which changed little from the January 2011 rate of 0.38%. In its 2012 rate cases, the Companies forecasted that the 30-day A-2/P-2 commercial paper rate would average 0.79% in 2013. In contrast, the 30-day A-2/P-2 commercial paper rate averaged 0.30% that year, even lower than the March 2012 rate of 0.45%. Staff Ex. 3.0 at 4.

In summary, Staff argues that the Companies' proposal to base the cost of new short-term debt issues on interest rate forecasts should be rejected in favor of recent actual short-term interest rates because the latter have proven to be more accurate predictors of future interest rates than the former. Staff Ex. 8.0 at 3-4.

Commission Analysis and Conclusion

The Commission finds that Staff's predictions of the cost of short term debt are reasonable, supported by the evidence, and are hereby adopted. Staff's predictions have been far more accurate in recent years than the Companies'. The short term interest rates which the Companies have urged us to incorporate in their rate structures relying on estimates by forecasting services have consistently overstated the actual interest rates that existed in the market place during the periods in question. The Commission finds that the cost of short term debt for North Shore should be .74%. The cost of short term debt for Peoples should be .91%.

D. Cost of Long-Term Debt

Companies' Position

North Shore (Uncontested)

A utility's forecasted cost of long-term debt is comprised of two components, the "embedded" cost of pre-existing debt issuances and the forecasted cost of issuances expected to occur during the test year (if any). North Shore's 2015 long-term debt cost forecast is 4.13%, and is based entirely on existing issuances because North Shore plans no new issuances in 2015. NS Ex. 2.3. The Companies and Staff agree on a long-term debt cost of 4.13% for North Shore. Staff Ex. 3.0 at 6-7; NS-PGL Ex. 2.0 at 7.

Peoples Gas

Including the forecasted costs of its planned issuances in 2015, Peoples Gas originally forecasted its cost of long-term debt to be 4.72%. PGL Ex. 2.3. Due to the actual pricing of certain debt and newer forecasts, however, Peoples Gas' proposed long-term debt cost fell from 4.72% (PGL Ex. 2.3) on direct to 4.32% (NS-PGL Ex. 34.2P) on rebuttal. The late August price of Peoples Gas' Series BBB, 4.21% was lower than both the Utility's forecasted price of 4.72% and Staff's 4.66% based on the June 11, 2014 actual rate. NS-PGL Ex. 34.0 at 3.

Staff proposed a 4.36% cost for Peoples Gas' long-term debt based on the June 11, 2014 spot day yield on A-rated bonds. Staff Ex. 3.0 at 6-7. The Companies argue that Staff's approach is inconsistent and arbitrary. NS-PGL IB at 100. While Staff agreed that the actual pricing of issuances should be used as it became known, Staff applied the 3.90% cost Peoples Gas obtained on its Series VV municipal bond remarketing in July to the Series WW municipal bond remarketing Peoples Gas does not expect to make until August 2015. Staff used the actual cost of Peoples Gas' Series VV remarketing as the forecasted cost for its Series WW remarketing instead of adjusting "current" municipal bond yields from *Vanguard* "for the difference in years to maturity on the proposed new issuances," as Staff did on direct. *Compare* Staff Ex. 8.0 at 7 *with* Staff Ex. 3.0 at 6-7.

The Companies note that this inconsistent mixing of methods avoided any changes to Staff's initial position based on June 11, 2014, actual interest rates. NS-PGL IB at 100; see Staff Ex. 8.0 at 7. The Companies argue that absent a sufficient rationale for the change, which has not been presented here, the Commission should insist on consistency of method in the highly complex area of corporate finance, which is the subject of many theories and data sources. Indeed, forecasting the cost of debt is itself "highly dependent on analyst judgment as to the inputs, and therefore subject to manipulation." Docket Nos. 09-0166/09-0167 (Consol.), Order at 123. For these reasons, the Companies urge the Commission to adopt their proposed long-term debt forecasts, even though the result will be a slightly lower cost for Peoples Gas (4.32% instead of 4.36%).

<u>Staff's Position</u>

The Companies and Staff agree that 4.13% is a reasonable estimate of North Shore's embedded cost of long-term debt for average 2015. Staff Ex. 3.0 at 6; NS Ex. 2.0 at 7. The Companies and Staff do not agree on the embedded cost of long-term debt for Peoples Gas, due to the Companies' use of forecasted interest rates for the anticipated 2015 issuances.

Staff and the Company agree on the interest rates for all long-term debt issues except those planned for 2015. Staff Ex. 8.0 at 7, Sch. 8.02P. Peoples Gas completed the pricing for the Series BBB bonds in August, with the actual interest rate set at 4.21%, after Staff filed its rebuttal testimony. NS-PGL Ex. 34.0 at 3. Hence, the interest rate for the Series BBB on line 12 of Staff Schedule 8.02P should be changed from 4.66% to 4.21% to reflect the actual interest rate. This change reduces the embedded cost of long-term debt for Peoples Gas from 4.36% to 4.26%. Attachment A.

The interest rates for the planned 2015 issuances should be based on recent actual interest rates. For the tax exempt Series WW planned to be issued in 2015, Ms. Freetly used the actual 3.90% interest rate that the Company recently obtained on the similar tax exempt Series VV. Staff Ex. 8.0 at 7, Sch. 8.02P, line 13. For the non-tax exempt Series CCC planned issuance for 2015, Ms. Freetly used the current yield on 30-year A-rated corporate bonds of 4.66%. Staff Ex. 3.0 at 7; Staff Ex. 8.0 at 7; Sch. 8.02P, line 14.)

Forecasted interest rates should not be used for estimating the cost of the planned 2015 issuances of long-term debt for Peoples Gas. Academic research has shown that forecasters' predictions of future movements of interest rates are inaccurate. Indeed, one financial text states, "forecasting interest rates is a perilous business. To their embarrassment, even the top experts are frequently wrong in their forecasts." Forecasts are frequently wrong even in the direction, let alone the magnitude and timing, of future interest rate changes. For example, the November 1, 2013 Blue Chip forecasts that Company witness Moul relied on (NS and PGL Ex. 3.12, 2) is already proving to be inaccurate. Blue Chip forecasted increasing yields from the fourth quarter 2013 through the second quarter of 2014. However, the actual yields have fallen over that time period.

Commission Analysis and Conclusion

The Commission finds and concludes that 4.13% is a reasonable estimate of North Shore's embedded cost of long-term debt for average 2015 and is supported by the evidence.

The Commission finds that Staff's estimate of the cost of Peoples' long term debt is compelling and supported by the evidence. While the Commission agrees that it is unlikely that current interest rates for long term debt will continue to be available in 2015, the Commission also believes that predicting the direction, magnitude, or timing of future interest rate changes with accuracy is not possible. The Commission observes that the record demonstrates that professional forecasting services relied on by the Companies have consistently over estimated future rates in recent years. Current interest rates have proven to be better predictors of future interest rates than professional forecasters. Therefore, the Commission concludes that the appropriate estimate of Peoples cost of long term debt should be 4.26%

E. Cost of Common Equity

Companies' Position

The Commission "is charged by the legislature with setting rates which are 'just and reasonable' not only to the ratepayers but [also] to the utility and stockholders." *BPI II*, 146 Ill. 2d at 208-209. Ratesetting by the Commission "involves a balancing of the investor and consumer interests." *Citizens Utility Board, et al. v. Illinois Commerce Comm'n,* 276 Ill. App. 3d 730, 736, 658 N.E.2d 1194 (1994) (quoting *Illinois Bell Tel. Co. v. Illinois Commerce Comm'n,* 414 Ill. 275, 287, 111 N.E. 2d 329 (1953)).

The Companies are entitled to fair and reasonable returns on their investment, returns that are "reasonably sufficient to assure confidence in the financial soundness of the utility and adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." *Bluefield Water Works & Improvement Co. v. Public Service Comm'n of the State of West Virginia*, 262 U.S. 679, 693 (1923). The returns authorized by this Commission "should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). This Commission "fully embraces the principles set forth" in *Bluefield and Hope. Consumers Ill. Water Co.*, Order at 41, Docket 03-0403 (April 13, 2004).

The Commission has recognized that its decisions directly affect the Companies' credit ratings and the capital costs that they pass on to their customers:

> We are cognizant that the Commission's ratemaking decisions are increasingly important to the Companies' ability to maintain investment grade credit ratings and reasonable capital costs. Indeed the quality and direction of regulation, in particular the ability to recover costs and earn a reasonable return, are among the most important considerations when a credit rating agency assesses utility credit quality and assigns credit ratings. . . . [S]tate commissions play a critical and relevant role in defining the market for utility capital, and we understand that this Commission's decisions play a larger role in setting the Companies' actual capital costs. <u>The bottom line impact of setting a rate of return too low, unless warranted, could have a deleterious [effect] on a utility's ability to deliver quality service as well as higher credit costs that will make their way to each ratepayer[']s bill.</u>

Docket Nos. 11-0280/11-0281 (Consol.), Order at 137 (emphasis added). Accordingly, "[a]llowing a utility the opportunity to recovery fully its costs of service, including its costs of capital, is in the long-term interests of customers, because this is necessary in order for the utility to be able to provide adequate, safe, and reliable service over time at the least long term cost." *Id.* at 5.

Understood properly, the courts' admonishment that the Commission balance customer and investor interests in ratemaking does not mean, as the AG argues, that the Commission can consider adjustments to a utility's ROE in order to reduce rates paid by low income customers. AG IB at 6-7. The Companies argue that supportive ROE decisions are in the interest of both customers and shareholders by maintaining the Companies' financial strength and their access to capital at reasonable cost. The Commission, however, has many ways to address customer impact, such as its policies on energy efficiency and customer matters such as bill payment NS-PGL RB 82.

Traditionally, the Commission has established the utility's authorized return on equity by employing financial models designed to estimate a firm's market cost of equity. In recent cases, however, the Commission has recognized that the financial models have theoretical limitations and are "highly dependent on analyst judgment as to the inputs, and therefore are susceptible to manipulation. Although these models provide the best information of what we need for the purposes at hand, their limitations require that we also consult general financial market information to ensure that the model results presented us are…reasonable rates of return on equity based on the models that we deem appropriate for our consideration." Docket Nos. 09-0166/09-0167 (Consol.), Order at 123. More recently, the Commission reiterated that it will consider current market conditions and trends, including the returns recently authorized for other Companies, in addition to the financial model results, "provided the data are verifiable and unbiased." Docket Nos. 12-0511/12-0512 (Consol.), Order at 205. Such general market data "provide relevant comparative information" for the Commission's assessment of the parties' cost of equity evidence. *Id.*

Earlier this year, the Federal Energy Regulatory Commission ("FERC") reached similar conclusions, rejecting the "mechanical application" of the DCF model and expanded its "zone of reasonableness" inquiry to include results from the Risk Premium, CAPM and Expected Earnings approaches as well as "record evidence of state commission-approved ROEs." *Martha Coakley, Mass. Attorney Gen.*, Docket No. EL11-66-001, 147 FERC ¶ 61,234 (2014), at 142 148

The "verifiable and unbiased" evidence of general market conditions and trends in this case uniformly lead to the conclusion that the Companies' cost of equity will be higher in 2015 than it was in 2013, when the Commission last set the Companies' rates. Stellar stock market performance and increasing strength in the leading economic indicators point to an improving economy. PGL Ex. 3.0 at 20-21. Treasury and utility bond yields are projected to rise due to the Federal Reserve's tapering of its program to support the economy in response to the 2008 financial crisis. *Id.* at 28, 31-32; NS-PGL Ex. 19.0 at 11-12.

Consistent with these leading economic indicators, forecasted returns for the Delivery Group are projected to average 10.50%, which is substantially higher than the Companies' current authorized return of 9.28%. NS-PGL Ex. 19.0 at 4-5. This forecasted growth is consistent with growth in the average authorized returns for natural gas Companies from 9.68% in 2013 to 9.71% in the first half of 2014. *Id.* at 3. Indeed, the average return in the second quarter of 2014 was 9.84%. CCI Ex. 2.0 at 5 (table).

The Companies find Staff's continued objections to the consideration of ROEs authorized for other Companies "grossly exaggerated" for at least three reasons. First, Staff's position is contrary to this Commission's and now FERC's pronouncements that other authorized returns should be considered as "indicators" to ensure that the return set in an individual case meets constitutional standards. Second, the Companies' evidence of other returns was restricted to 2013 and 2014 and therefore captured "market fundamentals that are closely aligned with the present." NS-PGL Ex. 35.0 at 4. The Companies' evidence was also based on a large sample, which encompassed the diversity of risk characteristics and minimizes the effect of any given factor. *Id.* Neither Staff nor CCI disputed that the Companies' risk characteristics are reasonably similar to natural gas distribution companies generally. Third, credit ratings among Companies are "tightly clustered" and do not represent a likely source of variation in authorized returns. The same is true for flotation costs, as few commissions adjust for them. *Id.* at 4-5.

For all of these reasons, the Commission should continue its practice of considering general market conditions and trends, including recent authorized returns for other Companies, in its assessment of the parties' positions on the Companies' authorized return and the evidence underlying those positions. Doing so does not mean, as Staff and CCI claim, that the Commission would be basing its ROE decisions on such data. NS-PGL IB at 102-104.

Moreover, the Companies explain that Staff's own contextual information in the form of various calculations of a cost of equity for the U.S. market "as a whole" should be rejected. NS-PGL RB at 82-83. Staff claims that a 9.0% ROE for the Companies is "representative of the return investors can earn on other investments of comparable risk because the overall U.S. market cost of equity is anywhere from 8.80% to 9.52%. Staff IB at 57-58. Staff fails, however, to explain how the Commission is to use this measurement to determine the return on investments of risk comparable to the Companies, other than the unsupported claim that the "market as a whole" is riskier than gas distribution Companies. *Id.* at 58.

Moreover, Staff did not explain how these published measurements of the "market" cost of equity deviated so dramatically from Staff's own calculation of the "expected rate of return on the market" for purposes of its CAPM model. NS-PGL RB at 83. Based on a DCF analysis on the firms in the S&P 500 Index, Staff calculated that cost to be 12.43%. Staff Ex. 3.0 at 17. By comparison, the Companies calculated the total return on the market of U.S. equities to be 10.90%. PGL Ex. 3.0 at 33.

The Companies argue that the most direct calculation of investments of risk comparable to the Companies is Mr. Moul's Comparable Earnings model, which estimates "the returns realized by non-regulated firms with comparable risks to a public utility." PGL Ex. 3.0 at 35. Using six categories of comparability of risk to the Delivery Group and reviewing both historical and forecasted returns for non-utility companies, Mr. Moul calculated a 10.30% ROE for investments of comparable risk to the Companies, which is very close to his recommendation based on his other models. *Id.* at 37.

The Companies conclude that all of these considerations support an increase of the Companies' ROE to 10.25%.

<u>Proxy Group Analysis</u>

Because the Companies' stock is not publicly traded, their cost of equity must be estimated using mathematical models applied to a proxy group of publicly-traded companies with investment risk similar to that of the Companies. NS Ex. 3.0 at 4. Mr. Moul based his 10.25% ROE recommendation using three market-based mathematical models based on a proxy group of publicly-traded gas and electric distribution Companies (the "Delivery Group"): the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM") and the Risk Premium ("RP") model. Mr. Moul developed inputs to the models based on his independent evaluation of the types of historical, current and forecasted information that is readily available to and routinely relied upon by investors and financial analysts. Mr. Moul presented the following calculations of the Companies' market cost of equity:

Model	Cost
DCF	9.71%
RP	11.50%
CAPM	9.62%
Average	10.25%

PGL Ex. 3.0 at 6.

Staff accepted the Companies' Delivery Group for the purpose of running its cost of equity models. Staff Ex. 3.0 at 9, 18. CCI, however, used a different proxy group comprised of all but two of the Delivery Group companies. One company was properly excluded because it became an acquisition target in the time between the Companies' and CCI's analyses. CCI also excluded Laclede Group because it is pursuing an acquisition of another company. CCI did not justify this exclusion, pointing only to the fact that a credit rating agency had placed the company on watch for potential downgrade. *See* CCI Ex. 2.0 at 9-10. CCI did not provide any evidence that Laclede Group's proposed acquisition impacted the company's fundamentals. NS-PGL Ex. 19.0 at 18.

The weight of the evidence favors the use of the Delivery Group to estimate the Companies' cost of equity. CCI's reliance on a different proxy group was not justified and therefore its analyses are not comparable to those of the Companies or Staff. Accordingly, the Commission should disregard CCI's analyses.

DCF Analysis

The DCF model expresses the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return, which for common stock is the dividend yield plus future price growth. NS Ex. 3.0 at 14. Mr. Moul used a six-month average dividend yield for the Delivery Group, adjusted by three generally accepted methods to reflect investors' expected cash flows, and averaging the three adjusted values. *Id.* at 15-16. For the investor-expected growth rate, Mr. Moul evaluated an array of historical and forecast growth data from sources that are publicly available to, and relied upon by, investors and analysts. *Id.* at 17-18. He focused on forecasts of earnings *per* share growth because empirical evidence supports it and because they are most relevant to investors' total return expectations. *Id.* at 18-20. He selected 5.25% to reflect improving business conditions. *Id.* at 20.

Mr. Moul then applied a financial leverage adjustment to his DCF results because they are based on market prices of the Gas Group's stock, which imply a capital structure with more equity and less financial risk, but are applied to utility book values, which imply a capital structure with less equity and more financial risk. *Id.* at 22-25.

The Companies argue that Staff's and CCI's DCF model results are too low to be credible, and are the result of inappropriate or biased inputs, as well as unsupported methodologies.

Staff's Failure to Adopt Mr. Moul's Dividend Yield is Unsupported

In response to Mr. Moul's renewed criticism of Staff's continued reliance of spot day stock prices to develop its DCF dividend yield, Staff chose not to defend its practice. Instead, "in order to reduce issues in this proceeding," Staff stated that would "adopt" Mr. Moul's "6-month average dividend yield of 3.89%." Staff Ex. 8.0 at 11. Staff thus implied that it was conceding to the dividend yield that Mr. Moul used in his DCF model, but this was not the case. Mr. Moul actually used a dividend yield of 4.00% "to reflect the prospective nature of the dividend payments." PGL Ex. 3.0 at 16; see PGL Ex. 3.6. The Companies state that Staff did not explain, much less justify, why it did not "adopt" Mr. Moul's actual dividend yield. NS-PGL IB at 107.

Staff Makes Unsupported Departures From Its Prior DCF Methodologies Resulting in Reduced Results

The Companies note that the Commission has been troubled in the past by Staff's departures from established methodologies that result in lower costs of equity through the models. For example, in the Companies' 2009 rate cases, the Commission rejected Staff's DCF result because Staff had departed from its constant-growth version of the model without justification. *Peoples Gas 2009 Order* at 124-125. The Companies argue that in this case, Staff has once again departed from past practice without sufficient explanation and the result is a lower DCF result.

In prior cases, including the Companies' last four rate cases, Staff has based its DCF growth component on security analyst forecasts of earnings *per* share ("EPS") growth for the proxy group. *Peoples Gas 2012 Order* at 198 (Zacks and Reuters); *Peoples Gas 2011 Order* at 126 (Zacks); Peoples Gas 2009 Order at 104 (Zacks); *Peoples Gas 2007 Order* at 78 (Zacks, Yahoo and Reuters). In this respect, Staff's approach has been consistent with that of the Companies, though they have not necessarily agreed upon which forecasts to use in a given case.

In this case, however, Staff calculated its DCF growth rate differently. First, Staff did not rely on Zacks and/or Reuters EPS growth forecasts as it did in the past. Instead, it relied on the group of four published EPS growth forecasts identified by Mr. Moul, which included Zacks but not Reuters. Instead of averaging the Value Line EPS growth forecast with the other EPS growth forecasts, however, Staff first averaged that forecast with Value Line growth forecasts for several other parameters in order to arrive at an average Value Line growth forecast. Staff Ex. 3.0 at 9. This average Value Line growth forecast of 4.47% was over 100 basis points lower than the Value Line EPS growth forecast of 5.58%. *See* PGL Ex. 3.8. Staff then averaged its average Value Line growth forecast with the EPS growth forecasts from I/B/E/S First Call (4.87%), Zacks (5.10%) and Morningstar (4.70%) to arrive at its DCF growth rate of 4.77%. Had Staff simply averaged the four EPS growth forecasts, its DCF growth rate would have been 5.06%. PGL Ex. 3.0 at 19.

By contrast, Mr. Moul considered both historical and forecasted growth data and did not simply average selected values. Because "[e]arnings *per* share growth is the primary determinant of investors' expectations regarding their total returns in the stock market," Mr. Moul focused on EPS growth forecasts. With the EPS growth forecasts ranging from 4.70% to 5.58%, Mr. Moul selected a DCF growth component of 5.25% to reflect improving business conditions. PGL Ex. 3.0 at 19-21.

Staff did not claim that the Value Line EPS growth forecast was biased, inaccurate or otherwise faulty. In fact, when Mr. Moul objected to the mishmash nature of Staff's DCF growth component, Staff witness Ms. Freetly agreed to exclude the Value Line growth forecasts for book value *per* share, cash flow *per* share and percent retained to common equity. Staff Ex. 8.0 12. She insisted, however, on blending the Value Line EPS growth forecast with the Value Line growth forecast for dividends *per* share ("DPS"). *Id.* at 12. By averaging the much lower DPS rate (3.92%) with the EPS rate (5.58%), Staff reduced the Value Line component to 4.75% and its DCF growth rate from 5.06% to 4.82%. *Id.* at 13:237.

Staff claims, without citation to the record, that it has used forecasted DPS growth rates in the DCF model "when available from Staff's growth rate sources." Staff IB at 51.

Yet Staff can identify only one instance from over 23 years ago. *Id.*, citing Order, Docket No. 90-0169 (Mar. 8, 1991).

Staff also claims that it "usually relies on growth rates from Zacks and Reuters for the DCF model, which do not provide projected growth in dividends *per* share; they only publish growth in earnings *per* share." *Id.* If this is true, then it must also be true that Staff does not use DPS growth forecasts for the growth component of the DCF model.

Additionally, the Companies argue that Staff introduced a double counting issue into its DCF model because the forecasted dividend yield for the Delivery Group is already included in the DCF model. Had Staff limited its averaging to the EPS forecasts, its DCF growth rate would have been 5.11% instead of 3.89%. NS-PGL Ex. 19.0 at 8. Coincidentally, had Staff followed its longstanding practice and relied on the Zacks EPS growth forecast (a Reuters forecast is not in the record), its DCF growth rate would have been 5.10%. *Id.*

Mr. Moul's Leverage Adjustment is Methodologically Sound

Consistent with his past analyses presented to this Commission, Mr. Moul has included a "leverage" adjustment in his DCF and CAPM models. PGL Ex. 3.0 at 21-26, 30-31. The Companies acknowledge that the Commission has not accepted this adjustment, but the Companies continue to urge its consideration because its underlying logic is unassailable.

The leverage adjustment is necessary to correct the measurement error that occurs when a market cost of equity that is based on the market value capital structure of the Delivery Group is applied to the Companies' book value capital structure. The market cost of equity assumes a capital structure with more equity, about 60%, and less risk that the Companies' book value capital structures, which include about 50% equity. PGL Ex. 3.9. If the Delivery Group's market cost of equity is 10.25% as estimated by

Mr. Moul, then the Companies would have to recover 10.25% times the market value of their equity to earn their market-based return. But because of the regulatory practice of applying the market-based cost of equity to the utility's book-value capital structure, the Companies by definition cannot earn their market-based return. PGL Ex. 3.0 at 22.

The leverage adjustment makes the Companies' market cost of equity applicable to their book value capital structures by accounting for the lower equity ratios and higher risk in those structures. In this case, the DCF return of 9.25% must be adjusted upward by 46 basis points to allow the Companies to earn their market cost of equity applied to their market value capital structures. *Id.* at 25- 26. Likewise, the CAPM beta must be adjusted upward from 0.69 to 0.75. *Id.* at 30-31.

Staff and CCI raise a number of familiar but unfounded objections to the leverage adjustment. First, Staff and CCI argue that Companies are allowed to earn a return only on the amount actually invested in providing utility service and the leverage adjustment would provide a return on amounts that are not invested in the Companies, contrary to Illinois law. Staff IB at 62-63; CCI IB 24-25. The Companies claim that this is pure sophistry. The Companies are not trying to earn on dollars that they have not invested;

rather, they are trying to earn the full cost of equity that is associated with their book value investment. NS-PGL RB at 87.

Second, Staff speculates that correcting the leverage mismatch between market returns and book value capital structures would result in a "never ending upward spiral" in utility market values and authorized ROEs. Staff IB at 62-63. The Companies argue that there is no basis for Staff's assertion that the "investor required return" is exactly the product of the authorized return and the book value of the utility's equity. If that was true, "then a stock price would always equal the firm's book value." NS-PGL Ex. 35.0 at 7. Of course, this is not true, as demonstrated by the prevalence of natural gas utility stocks trading at multiples of book value; the average multiple over the last 56 years is 1.72. *Id.* at 7-8. Clearly, authorized natural gas utility ROEs are not routinely set at Staff's notion of the "investor required return," and the result has not been a "never ending upward spiral" of market values and ROEs. NS-PGL RB at 87.

Third, Staff argues that a firm can have only one level of "intrinsic" risk. Staff IB at 66-67. The Companies do not disagree. However, the Companies state it is undeniable that if the market priced the Companies' equity assuming their book value capital structures, the cost would be higher than it is when the market assumes their market value capital structures. NS-PGL Ex. 19.0 at 15. A firm's financial risk as perceived by the market changes when the firm's capital structure changes. *Id.* at 16. The market will perceive more financial risk with an equity ratio of 50% than with an equity ratio of 60%. *Id.* at 17.

<u>CCI Failed to Support Its Use of a Non-Constant Form of the DCF Model</u>

In addition to two versions of the constant growth form of the DCF model, CCI presented a non-constant growth version. In the Companies' 2010 test year rate cases, the Commission rejected Staff's reliance on a non-constant growth form of the DCF model, noting that the constant growth model "has been favored by the Commission for years." Docket Nos. 09-0166/09-0167 (Consol.), Order at 124. The Commission found that Staff had not justified its departure from prior practice.

In contrast to the constant growth version of the DCF model, which assumes one, steady rate of future dividend growth, Staff's non-constant growth model assumes multiple stages of growth on the theory that, given the large difference between the near-term growth rates for the Gas Group and the expected long-term growth of the overall economy, the continuous sustainability of the near-term growth rates for the Gas Group is unlikely. Staff, however was unable to demonstrate the unsustainability of the analyst growth rates it relied on which we must assume took into account indicators of below average growth associated with the Gas Group, including earnings retention rates and risk/return. *Id.*

In addition, the Commission rejected "Staff's position that the non-constant growth form of the model must be used any time it can be claimed that analyst growth rates are not sustainable. Rather we will require a more robust showing that application of the constant model is appropriate." *Id.* at 125.

The Companies argue that CCI did not attempt to make this "more robust showing" required by the Commission for its non-constant growth model. To the contrary, Mr.

Gorman testified that his constant growth model "is a reasonable reflection of rational investment expectations over the next three to five years." CCI Ex. 1.0 at 21. He included a non-constant form of the model simply to reflect an "outlook of changing growth expectations." *Id.* at 21.

The Companies argue that for this reason alone, the Commission should disregard CCI's non-constant growth DCF model. NS-PGL IB at 109-110. If another reason was needed, the result of this model – 8.65% -- is far too low to be credible, even by CCI's own evidence of 2014 year-to-date gas utility ROEs, which average over 100 basis points higher. See CCI Ex. 2.0 at 5 (table).

Many Of CCI's DCF Results Are Far Too Low To Be Credible

The Commission has in the past rejected DCF results that are "anomalous." *Peoples Gas 2007 Order* at 92. Many of CCI's constant growth DCF rates for Delivery Group companies are so anomalous that they undercut the credibility of his DCF results. *See* NS-PGL Ex. 19.0 at 18 (table).

"It is a fundamental tenet of finance that the cost of equity must be higher than the cost of debt by a meaningful margin to compensate for the higher risk associated with common equity investment." NS-PGL Ex. 19.0 at 18-19. The six-month average yield on Baa-rated public utility bonds is 4.98%. *Id.* at 19. Even under Mr. Gorman's 30-year historical average equity risk premium of 3.80% (which is much lower than the more recent premiums in excess of 5.00%), his DCF results for 6 of the Delivery Group companies are far below the minimum expected cost of equity of 8.78%, much less the average 2014 authorized gas utility ROE of 9.71%. CCI Ex. 2.3. The Companies thus argue that these results should be disregarded.

CAPM Analysis

The CAPM determines an expected rate of return on a security by adding to the "risk-free" rate of return a risk premium that is proportional to the non-diversifiable, or systematic, risk of the security. This model requires three inputs: (1) the risk-free rate of return, (2) a "beta" that measures systematic risk, and (3) the market risk premium. For the risk-free rate of return, Mr. Moul used historical and forecast yields on 20-year Treasury bonds and selected a mid-point of 4.25% based on current forecasts and recent trends. NS Ex. 3.0 at 30-31. For the beta measurement of systematic risk, he used the average Value Line beta for the Gas Group, adjusted using the Hamada formula to reflect the application of this market-based measurement to the utility's book value capital structure used in ratemaking. NS Ex. 3.0 at 29-30. Mr. Moul developed his market premium of by averaging forecast data from Value Line and the S&P 500 Composite and historical data from Ibbotson Associates, all of which are sources routinely used by investors, analysts and academics. NS Ex. 3.0 at 31-32.

The Companies argue that the Commission should reject Staff's CAPM result of 9.27% for two reasons. First, it is based on historical spot day interest rates as of October 31, 2013, which have no relation to what interest rates are likely to be in 2015. Second, Staff's unique "beta" measurement of systematic risk is biased because it uniformly results in lower CAPM results. NS-PGL IB at 111-113.

According to Staff, an interest rate, stock price or other datum from a single day in the recent past is a better predictor of what that data point will be in the future than the forecasts made by governmental and commercial analysts on which investors and analysts routinely rely. The Companies note that it is undeniably true that few if any forecasts are exactly right in hindsight. Staff provided no evidence that information from a single day in the past provides a more accurate prediction than forecasts do when they are made. Logic and common sense dictate otherwise. All that a given day's interest rate reflects is the cost of a certain type of debt capital on that day. The Companies conclude that it says nothing about what that cost of capital will be in the future. *Id.* at 112.

Again, the Companies argue that under the Commission's prior decisions the question is whether the data in question are "verifiable and unbiased." Peoples Gas 2012 Order at 205. Here, Staff rejected interest rate forecasts published by Blue Chip in favor of historical spot day rates. The Companies posit that the credibility and objectiveness of the Blue Chip forecasts is undisputable:

Blue Chip does not actually make forecasts of interest rates itself. Rather, Blue Chip conducts a monthly survey of noted economists from academic institutions, banking, brokerage, business consulting, financial institutions, investment advisory firms, and rating agencies. Presently, there are forty-eight (48) contributors to the Blue Chip survey. Blue Chip takes the results of its monthly surveys and publishes the consensus of these individual forecasts. The major attributes of Blue Chip are its independence, the influence it has on investors' expectations of future interest rates, and the objectivity of the survey that encompasses the wide range of viewpoints obtained from a broad sample of renowned economists. NS-PGL Ex. 35.0 at 3. Staff did not challenge these attributes of the Blue Chip forecasts, which were also used in CCI's CAPM model. *See* CCI Ex. 1.0 at 29. The use of such "verifiable and unbiased" data in determining the Companies' cost of equity is entirely appropriate and superior to relying solely on historical spot day data to establish that cost in a future test year. NS-PGL IB at 112.

For this reason alone, the Companies conclude, the Commission should reject Staff's CAPM model. Alternatively, it should be adjusted to incorporate either Mr. Moul's Blue Chip-based risk-free rate of 4.25% or Mr. Gorman's rate of 4.30%. PGL Ex. 3.0 at 32 33; CCI Ex. 1.0 at 29.

Furthermore, as the Companies have noted in prior cases, Staff is not content to rely on the "betas" – the theoretical measurement of the systematic risk of the Delivery Group – published by well-recognized sources like Value Line. In addition to the Value Line betas, Staff in this case used betas published by Zacks but adjusted them downward because "[s]ome empirical tests of the CAPM suggest that the linear relationship between risk, as measured by the raw beta, and return is flatter than the CAPM predicts." Staff Ex. 3.0 at 20. Staff also averaged in a "regression beta" of its own creation. The Companies argue that there is no need for this additional beta measurement and it is not a data point on which any investor relies. By contrast, Value Line betas are routinely relied on by investors and thus used in the actual pricing of stocks by the market. NS-PGL Ex. 19.0 at 13. Accordingly, both the Companies and CCI relied on Value Line betas alone. CCI Ex. 1.12.

The Companies state that of more concern is the fact that the Staff betas are routinely lower than the published betas. NS-PGL Ex. 35.0 at 7 (table). Thus, the only purpose served by Staff's lower beta, according to the Companies, is to reduce Staff's CAPM result. In this case, had Staff relied solely on the published betas, its CAPM result would have been 9.71% instead of 9.27%. NS-PGL Ex. 19.0 at 13. If Staff had based its CAPM on the Value Line betas as the Companies and CCI did, the result would have been 9.82%. *Id.* at 13. Thus, even if there was some value in using multiple beta models (see Staff Ex. 8.0 at 14-15), Staff's "multiple source" approach is invalid because of its downward bias.

Risk Premium

The Risk Premium model measures the cost of equity by determining the degree to which equity has more risk than corporate debt, and adding that "equity risk premium" to the interest rate on long-term public debt. NS Ex. 3.0 at 25. Mr. Moul estimated a 5.25% prospective yield on A-rated utility bonds based on historical and forecasted yields. NS Ex. 3.0 at 26. Mr. Moul determined an equity risk premium of 6.25% by analyzing results for S&P Public utilities and then adjusting those results based upon the results of his fundamental risk analysis in comparing the results for the S&P Public utilities to the Gas Group. NS Ex. 3.0 at 26-28. Mr. Moul's risk premium analysis thus provided a cost of equity of 11.50%. NS Ex. 3.0 at 25.

Staff contends that the Risk Premium model is unreliable because the true mean of the market risk premium is unobservable and the result is influenced by the choice of historical period. The Companies respond that it is not necessary to establish the true mean because the risk premium approach is designed to align the risk premium with the level of forecasted interest rates. The risk premium rises as interest rates decline and the risk premium falls as interest rates increase. Mr. Moul's risk premium analysis is dynamic and does not rest upon a single risk premium that might be represented by the "true mean." NS-PGL Ex. 35 at 6. Second, Mr. Moul did not arbitrarily select any particular period to measure the risk premium with historical data. Rather, he used all available and reliable data in order to avoid the introduction of a particular bias into the results. *Id.*

Staff's Position

Staff witness Janis Freetly's estimate of the investor-required rate of return on common equity for Peoples Gas and North Shore is 9.05%. Staff's revised investor-required rate of return was derived by taking the average of Staff's revised 8.82% DCF estimate and 9.27% CAPM estimate results. Staff Ex. 8.0, Sch. 8.01. Ms. Freetly began her analysis with the data that the Companies' witness Mr. Moul used in his DCF and CAPM analyses while correcting the most significant flaws in those analyses. She applied both models to Mr. Moul's sample, the "Delivery Group." Staff Ex. 3.0 at 8.

DCF Analysis

DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments. Because a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend prices that stock prices embody. The companies in the Delivery Group pay dividends quarterly. Therefore, Ms. Freetly applied a quarterly DCF model. Staff Ex. 3.0 at 8-9.

In order to reduce issues in this proceeding, Ms. Freetly revised her DCF analysis in rebuttal testimony. Staff Ex. 8.0 at 11-13. While Staff does not agree with Mr. Moul's position that stock prices measured over a longer time period are superior for measuring the investor-required rate of return on common equity, Ms. Freetly adopted Mr. Moul's 6-month average dividend yield of 4.00%. In addition, Ms. Freetly agreed to exclude the Value Line projected growth rates for book value *per* share, cash flow *per* share and percent retained to common equity from the growth rate used in her DCF analysis; although, Mr. Moul had testified in his direct testimony that he considered those growth rates in his own analysis before he disowned them in his rebuttal testimony.

Staff supports a revised investor-required rate of return on common equity for Peoples Gas and North Shore of 9.05%. Staff witness Ms. Freetly began her analysis with the data that the Companies' witness Mr. Moul used in his DCF and CAPM analyses while correcting the most significant flaws in those analyses. She applied both models to Mr. Moul's sample, the "Delivery Group." Staff Ex. 3.0 at 8.

However, Staff argues that despite Mr. Moul's protestations to the contrary, the *Value Line* projected growth in dividends *per* share ("dps") should not be ignored. As Mr. Moul indicated, the Delivery Group average *Value Line* projected growth rate of earnings *per* share ("eps") is higher than the Delivery Group average *Value Line* projected growth rate of dps. DCF theory holds that dividend growth will equal earnings growth when the payout ratio is constant. NS-PGL Ex. 19.0 at 8. He then indicates that *Value Line* projects declining dividend payout ratios for the Delivery Group. *Id.* at 10. Staff states that this explains why *Value Line*'s forecasted eps growth rate exceeds its forecasted dps growth rate. If the lower payout ratio persists, long-term dividend growth will eventually converge to the level of earnings growth. This is because growth is directly related to the earnings retention ratio: Growth = Rate of Return on New Investment x Earnings Retention Rate.

Nonetheless, Staff argues that this higher long term earnings growth cannot be achieved without slowing near term dividend growth. Because the DCF is a dividend discount model rather than an earnings discount model, ignoring the slowing in the growth of dividends that is necessary to increase the earnings retention rate, leads to an upwardly biased estimate of the investor-required rate of return on common equity.

Significantly, Mr. Moul did not contest the economic rationale for including dps growth in DCF analysis described in the preceding paragraph. Rather, he alleged that Ms. Freetly's proposal to include growth in dividends *per* share in the DCF growth rate is a first for Staff and is therefore a departure from Staff precedent in past rate cases. (NS-PGL Ex. 35.0, 5.) However, Staff points out that it has used growth in dividends *per* share in the DCF model when available from Staff's growth rate sources. *See e.g. Docket No. 90-0169*, Order at 97 (March 8, 1991).

Using the data presented by Mr. Moul on NS and PGL Ex. 3.8, Ms. Freetly first calculated the average *Value Line* growth projection by averaging the growth in eps and dps. She then computed the average of the growth rates from I/B/E/S First Call, *Zacks*, Morningstar and the average *Value Line* growth projection. The resulting growth rate estimate is 4.82%. Hence, Staff's 8.71% DCF cost of common equity estimate was derived by adding the 4.82% growth rate to Mr. Moul's 3.89% dividend yield.

In Staff's Reply Brief, Staff agreed that Mr. Moul's actual dividend yield was 4.00%, not the 3.89% that Ms. Freetly used in her rebuttal testimony. NS-PGL IB at 107. According to Staff, adding the 4.00% dividend yield to Staff's 4.82% growth rate produces a DCF cost of equity estimate of 8.82%.

CAPM Analysis

The CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. For the beta parameter, Ms. Freetly supplemented Mr. Moul's *Value Line* betas with the *Zacks* betas and betas calculated using a regression analysis that the Commission has routinely adopted for the CAPM. Staff states that, because the *Zacks* beta estimate and the regression beta estimate are calculated using monthly data rather than weekly data (as *Value Line* uses), Ms. Freetly averaged the *Zacks* and regression results to avoid over-weighting betas calculated from monthly returns. She then averaged that result with the *Value Line* beta, which produced a beta for the Delivery Group of 0.64. Staff Ex. 3.0 at 17-21.

For the risk-free rate parameter, Ms. Freetly used the 3.66% yield on thirty-year U.S. Treasury bonds on October 31, 2013. Staff Ex. 3.0 at 15-17.

Finally, for the expected rate of return on the market parameter, Ms. Freetly conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market equals 12.43%. Staff Ex. 3.0 at 17. Inputting those three parameters into the CAPM, Staff's CAPM estimate of the cost of common equity for the Delivery Group is 9.27%. Staff Ex. 3.0 at 21; Sch. 3.06.

Staff points out that the Companies insist that the estimation of the risk-free rate should be based on forecasts rather than spot yields. NS-PGL Ex. 19.0 at 11-12. However, Staff argues that interest rates are constantly adjusting, and accurately forecasting the movements of interest rates is problematic, as discussed previously. In contrast, current U.S. Treasury yields, which Staff used to estimate the risk-free rate, are set directly by investors and reflect all relevant, available information, including investor expectations regarding future interest rates. Consequently, Staff states that investor appraisals of the value of forecasts are also reflected in current interest rates. Staff concludes that the Commission should continue to rely on current, observable market interest rates rather than the projected rates that Mr. Moul used in his analysis. Staff Ex. 8.0 at 13-14.

According to Staff, the Companies falsely contend that the interest rate forecasts are "verifiable and unbiased" and superior to relying solely on spot day data to establish the cost of equity in a future test year. (NS-PGL IB, 112.) Staff contends that the Companies' claim that the interest rate forecasts it relied upon are "unbiased" is demonstrably false. Also, Staff argues that there is no valid justification for disregarding investor expectations imbedded in objective, observable current market data in favor of a proxy for those expectations imbedded in speculative projections. Staff states that the forecasts Mr. Moul advocates are merely proxies for investor expectations. Proxies are a source of measurement error in cost of common equity estimation. Therefore, Staff argues proxies should only be used when the market factor in question is not directly observable.

Staff states that the Companies did not present any evidence that the *Value Line* betas are superior to Staff's. Because there is no inherently superior beta estimation methodology, multiple approaches result in less bias than merely relying on the higher *Value Line* betas. Hence, Staff concludes that the Commission should remain consistent with its past findings that use of multiple beta sources is beneficial to reduce measurement error and adopt Staff's beta in this proceeding. Staff IB at 53-55.

Leverage Adjustment

Mr. Moul argues that in order to apply a measurement of a return measured based on a firm's market-value capitalization compared to a book-value capitalization, the measurement must be adjusted before it is applied to the firm's capitalization measured based on book value. NS-PGL Ex. 19.0 at 17. His argument is effectively an espousal of fair-value rate making, which entails estimating the fair, or market, value of a utility's property and then applying a market ROE to that value. See., *e.g.*, *Union Electric Co. v. Illinois Commerce Comm'n*, 77 Ill.2d 364, 374-375 (1979). Section 9-210 of the Act put an end to fair-value ratemaking. 220 ILCS 5/9-210 ("For purposes of establishing the value of public utility property, when determining rates or charges, or for any other reason, the Commission may base its determination on the original cost of such property."). Mr. Moul's "leverage" adjustment would reverse that practice. The problem is that market to book ratio based adjustments to ROE would have the Commission fruitlessly "chase" market value. That would occur because market value is an inverse function of required rate of return and a direct function of expected cash flow. For example, if investors reduce their required rate of return, the market value will increase. If the Commission increases its authorized rate of return in reaction to that increase in market value, the utility's cash flow will increase, which in turn will lead to an even higher utility market value, which by Mr. Moul's reasoning would, necessitate an even greater upward adjustment to the authorized rate of return. These reactions -- investors reacting to the increased authorized ROR by raising market value and the Commission reacting to the increase in market value by raising the authorized ROR -- are mutually reinforcing, resulting in never ending upward spiral in both. Staff Ex. 8.0 at 17-20.

Another problem with the leverage adjustment is that it would boost authorized rates of return in response to successful diversification into non-utility businesses. Ms. Freetly used a hypothetical example to illustrate this phenomenon: a company that includes two business segments of equal book value and equal risk – a regulated gas delivery company that is expected to earn exactly the investor-required return and an unregulated segment that is expected to earn more than the investor-required return. Investors (*i.e.*, the market) would value the gas delivery segment equal to its book value because, at that price, investors would expect to earn exactly the return they require. However, investors would be willing to pay more than book value for the unregulated segment because of its higher-than-required earnings. Thus, the market value of the company as a whole would be bid up beyond its book value until the expected return equals the required return. Mr. Moul's argument suggests that the authorized return on rate base for the regulated gas delivery segment should be increased beyond the required return due to the excess expected earnings of the unregulated segment, which would, in turn, create excess earnings in the regulated gas delivery segment, pushing the market value higher still in a never-ending upward spiral. Staff Ex. 8.0 at 18.

Mr. Moul erroneously argues that if the results of the DCF, which are based on the market price of the companies analyzed, are used to compute the weighted average cost of capital based on a book value capital structure used for rate setting purposes, the utility will not recover its risk-adjusted capital cost because market value capital structures generally reflect less risk than book value capital structures. His argument suggests that when a company's market value exceeds its book value, the risk of a company increases if the capital structure is measured with book values of capital rather than market values of capital. Such a notion is without merit. The intrinsic risk level of a given company does not change simply because the manner in which it is measured has changed. Such an assertion is akin to claiming that the ambient temperature changes when the measurement scale is switched from Fahrenheit to Celsius. Mr. Moul has confused the measurement tool with the object to be measured. Specifically, capital structure ratios are merely indicators of financial risk; they are not sources of financial risk. Financial risk arises from fixed, contractually required debt service payments; changing capital structure ratios from a market value basis to a book value basis does not affect a company's debt service requirements; thus, it does not change the company's risk.

As noted in a corporate finance textbook by Brealey, Myers and Allen, there are a variety of ways to define leverage and there is no law stating how it should be defined. In any case, it is not appropriate to compare book value capital structures with market value capital structures any more than it would be appropriate to compare alternative measures of financial risk. Consequently, when assessing the relative financial risk of Peoples Gas and North Shore to the Delivery Group, Ms. Freetly compared the Companies' FFO interest coverage ratio to the Delivery Groups' FFO interest coverage. She did not compare the Companies' FFO interest coverage ratio to the Delivery Group's RCF to total debt ratio.

Further, the Staff's ratio analysis indicates that both North Shore and Peoples Gas have less financial risk than the Delivery Group. Hence, an upward adjustment to the cost of common equity for the Delivery Group is unwarranted. Staff Ex. 3.0 at 30-32.

Mr. Moul also argued that the Value Line betas cannot be used directly in the CAPM because they are derived based on market value. Hence, he unlevered and relevered the Value Line beta estimates for each of the companies in the Delivery Group for the book value common equity ratios using the Hamada formula. NS Ex. 3.0 at 29. His leverage adjustment is simply wrong because it relies on a comparison of two different measures of financial leverage: book value capital structures and market value capital structures. Staff Ex. 3.0 at 32.

Contrary to Mr. Moul's assertion, it is appropriate for the Commission to apply a market value derived cost of equity to the book value of common equity, even if the Companies' market value differs from its book value. Book value represents the funds a company receives from investors through security issuances on the primary market (*i.e.*, transactions directly between a company and its investors) and reinvestment of earnings. Book value does not adjust to reflect changing investor assessments of the level or riskiness of future cash flow; it only measures how much money the company has invested in assets that serve its customers.

In contrast, the market value is the price investors are willing to pay each other for a security on the secondary market. That is, market value is set by transactions between investors rather than transactions between the company and its investors; therefore the market value of a company's securities has no direct bearing on the amount of funding the company has to invest in assets. Cost of common equity analysis uses market value data because market data continuously adjusts to reflect investor return requirements as they are continuously re-evaluated.

The market value of a stock would grow to exceed its book value only if investors expected to earn a return above their required return. If that is the case, the market value will adjust upward until the expected return once again matches the required return. Thus, the market value always reflects the investor-required return, regardless of the book value. That is why it is appropriate, indeed necessary, to use a market-based cost of common equity for regulatory rate setting. Similarly, book value always represents the funds available to the company to invest in assets serving its customers, regardless of the market value. That is why it is appropriate and necessary to use a book value rate base for regulatory rate setting. The application of the market required return to the book value rate base simply takes the return investors demand to earn from a dollar invested in the common equity of a company, given the amount of risk in the common equity of the company and the current price of risk, and applies it to the number of common equity dollars invested in the rate base of the Companies. Staff Ex. 8.0 at 18-19.

Taken together, eliminating the inappropriate leverage adjustments to his DCF and CAPM estimates would produce a cost of common equity of 9.22% [(9.25% + 9.19%)/2]. Incorporating a more appropriate growth rate estimate in Mr. Moul's DCF analysis produces a cost of common equity of 9.00% [(8.82% + 9.19%)/2]. These corrected costs of equity estimates are significantly lower than the 10.25% he recommends for both Companies and is consistent with Staff's recommendation.

The Commission has properly rejected the use of leverage adjustments in several prior proceedings. Docket Nos. 01-0528/01-0628/01-0629 (Consol.), Order at 12-13 (March 28, 2002); Docket Nos. 99-0120/99-0134 (Consol.), Order at 54 (August 25, 1999); Docket No. 94-0065, Order at 92-93 (January 9, 1995). In fact, Mr. Moul presented, and the Commission rejected, the exact same leverage adjustment, based on the same arguments, in the Companies' 2007 and 2009 rate cases. Docket Nos. 07-0241/07-0242 (Consol.), Order at 95-96; Docket Nos. 09-0166/09-0167 (Consol.), Order at 128-129. The Commission's Order from the 2007 rate case quite clearly sets forth, in great detail, the reasons such a leverage adjustment should be rejected once again in this proceeding:

> In the Commission's judgment, the book value capital structure reflects the amount of capital a utility actually utilizes to finance the acquisition of assets, including those assets used to provide utility service. In establishing the overall or weighted average cost of capital, the proportion of common equity, based on the book value capital structure, is multiplied

> by market-required return on common equity. The Commission has used this approach in establishing utility rates for at least twenty-five years. (e*.g.*, *Ameren Order*, Docket Nos. 06-0070/06-0071/06-0072 (Consol.) *at* 141) ("[t]he Commission observes that it has repeatedly rejected arguments in favor of using market-to-book ratios as the basis for establishing cost of common equity"). Market value is not utilized in this calculation because it typically includes appreciated value (as reflected in its stock price) above the Companies' actual capital investments….
>
> Further, the Companies have failed to establish why a mismatch between the financial risk reflected in the book value and market value capital structures is problematic. If the Companies were correct that regulatory commissions, including this one, have been understating the market-required return on equity for twenty-five years, then the market values of common equity for Companies would not have remained well above the book values during that time. A practice of routinely understating the market-required return on common equity would have surely driven down the market values of common equity to near book value, but that has not happened. Accordingly, the Commission does not agree that an adjustment to the market required return on common equity is necessary to reflect the difference in financial risk between book value and market value capital structures. Therefore, we reject the Companies' financial leverage adjustment to their DCF results and their proposal to impose a similar leveraging adjustment to the betas used in their CAPM analysis.

Docket Nos. 07-0241/0242 (Consol.), Order at 95-96.

<u>CCI's Position</u>

<u>Overview</u>

Mr. Moul proposes a 10.25% cost of common equity for the Companies. The Companies' proposed cost of equity is more than 100 basis points higher than any other expert estimate in the record. Staff's expert Janis Freetly concluded that a 9.05% cost of equity is appropriate. CCI's expert witness, Michael Gorman, recommends a 9.15% cost of common equity. Mr. Gorman's analyses identified that return on equity as fair compensation for the Companies' investment risk and as adequate to preserve the Companies' financial integrity and credit standing. CCI Ex. 1.0 (Gorman) at 2. Mr. Gorman's recommended return satisfies the criteria of the U.S. Supreme Court's hallmark Bluefield Water Works and Hope Natural Gas decisions: 5 returns that are adequate to

(a) maintain financial integrity, (b) attract capital on reasonable terms, and (c) approximate returns on investments in other firms of comparable risk.

Mr. Gorman's risk-based estimate of the Companies' market cost of common equity is reasonable and should be adopted. To avoid excessive rates for the Companies' delivery service customers, the recommendation of the Companies' witness, Mr. Moul must be rejected.

The Companies' Investment Risk

Mr. Gorman began his cost of equity analysis with an assessment of utility industry investment risk, credit standing, and stock price performance. He concluded that "the market continues to embrace the utility industry as a safe-haven investment, and views utility equity and debt investments as low-risk securities." CCI Ex. 1.0 at 5. The market views the Companies similarly, with credit rating agencies characterizing their business risk as "Excellent" and finding their financial risk "Significant," but also noting their cash flow from "low-risk regulated gas distribution operations." CCI Ex. 1.0 at 7-8.

Accurate, risk-based estimates of the Companies' market-required return, as quantified by the DCF and CAPM models relied upon by this Commission, would reflect that unchallenged market perspective. The estimates of Mr. Gorman and Ms. Freetly do so. Mr. Moul's outlier recommended estimate does not.

CCI's Cost of Equity Analyses

To develop his recommended cost of equity estimate, Mr. Gorman performed three versions of the Discounted Cash Flow ("DCF") model analysis, and a Capital Asset Pricing Model ("CAPM") analysis. Because shares in the Companies are not publicly traded, Mr. Gorman's model analyses used a proxy group of publicly traded companies that have investment risk similar to NS-PGL. CCI Ex. 1.0 at 11. With two exceptions, Mr. Gorman's proxy group is the same as the proxy group used by the Companies' witness and Staff. Mr. Gorman omitted two firms because of their involvement in significant merger and acquisition activity, which affects their underlying fundamentals. CCI Ex. 1.0 at 12, 13.

DCF Analyses

For his DCF analyses, Mr. Gorman used distinctive growth inputs to reflect changes in growth expectations across near-term, transition, and long-term periods. The DCF method uses stock price, dividends, and a growth estimate to estimate the market-required return. Mr. Gorman conducted separate constant growth analyses using (i) consensus analysts' growth projections, and (ii) a sustainable growth estimate based on an internal growth methodology, and his third DCF analysis was a multi-stage model that used (iii) near-term, transition, and long-term growth estimate inputs. See CCI Ex. 1.0 at 14-15 and 17-27. The results of Mr. Gorman's DCF models are shown Table 2 of CCI Exhibit 1.0 at 27:

Constant Growth DCF Model (Analysts' Growth)	8.50%
Constant Growth DCF Model (Sustainable Growth)	9.50%
Multi-Stage Growth DCF Model	8.65%

Mr. Gorman concluded that the high end of this range was unreasonable, because the underlying growth rate far exceeded the current consensus of industry analysts and economists, regarding the expected pace of long-term growth in the overall economy. CCI Ex. 1.0 at 27, 43. These forecasts included, for example, projections published by "Blue Chip Financial Forecasts," U.S. EIA in its "Energy Outlook," and the Congressional Budget Office. CCI Ex. 1.0 at 25-27. Mr. Gorman determined that the midpoint of the range of his DCF results represented the best estimate of the Companies' current market cost of equity. CCI Ex. 1.0 at 27.

CAPM Analysis

Mr. Gorman's final analysis used the CAPM method, which estimates the cost of equity by adding a market risk premium, as modified by a measure of firm specific risk (beta), to a risk-free rate. Mr. Gorman conducted his CAPM analysis using Treasury bond returns as the risk-free rate, an average of historical and forward-looking market risk premium estimates, and the proxy group's average *Value Line* beta. The results of this analysis defined a cost of equity range with a midpoint of 9.24% (rounded to 9.25%).

Recommended Return

Mr. Gorman's recommended cost of common equity is 9.15%, the approximate midpoint between his DCF (9.0%) and CAPM (9.25%) estimates. CCI Ex. 1.0 at 33. By comparing the Companies' key credit rating financial ratios at his recommended equity return level (see CCI Ex. 1.0 at 34-36) with established ratings criteria, Mr. Gorman determined that the Companies' financial integrity is maintained. Based on the most recent S&P Financial Ratio Credit Metric Methodology, the Companies have "Excellent" business risk profiles. In addition, the Companies enjoy a "Significant" financial risk profile, which is more favorable than the "Aggressive" profile most Companies have. CCI Ex. 1.0 at 34. In particular, Mr. Gorman's analysis of the key financial benchmark ratios in S&P's credit rating review showed that, at his recommended 9.15% return on equity and using NS-PGL's proposed capital structures, the Companies' financial credit metrics are supportive of their current investment grade utility bond rating. CCI Ex. 1.0 at 36.

The Companies' witness Mr. Moul recommends a 10.25% cost of equity. His analyses produced a cost of equity estimate of that magnitude only by incorporating adjustments and approaches (discussed below) that the Commission has consistently rejected, and which are not consistent with industry norms. Specifically, Mr. Moul's DCF analyses incorporate a leverage adjustment and an unsustainable growth rate. His CAPM analysis incorporates a leverage adjustment into the beta, and it uses an arbitrary market risk premium. In addition, he offers a discredited Risk Premium analysis, which itself incorporates an arbitrary risk premium estimate. See generally CCI Ex. 1.0 at 37-51.

Mr. Moul's DCF analysis results are artificially inflated by a leverage adjustment of 46 basis points. PGL Ex. 3.0, at 25-38. That leverage adjustment has the effect, if not the purpose, of allowing the Companies to earn the Commission-determined equity return on an appreciated stock price paid in secondary markets, rather than on the actual investment used to provide regulated utility service -- viz., the Companies' book value rate base. *See* 220 ILCS 5/9-211 (rates may be set using only investment actually used to provide service). Secondary market transactions consist of stock market transactions among shareholders and provide no incremental investment devoted to utility service.

Moreover, any theoretical basis for the adjustment is dubious. Despite claiming to capture the cost of using a market value (as opposed to book value) capital structure, Mr. Moul acknowledged: "I know of no means to mathematically solve for the 0.46% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value." PGL Ex. 3.0 at 25-26. As Mr. Gorman observed, even "if those [Mr. Moul's leverage] arguments had any theoretical validity, they lack a factual basis and are also inconsistent with relevant industry practices." CCI Ex. 1.0 at 40.

Mathematically, the Companies' proposed leverage adjustment is the same as applying the unleveraged market required return to an inflated rate base. CCI Ex. 1.0 at 40. That is clearly unlawful, because a regulated utility is allowed its authorized rate of return only on amounts actually used to provide utility service. 220 ILCS 5/9-211. "Market value is not utilized in this calculation because it typically includes appreciated value (as reflected in its stock price) above the Companies' actual capital investments." Docket Nos. 07-0241/07-0242 (Consol.), Order at 96; 220 ILCS 5/9-211.

Mr. Moul's DCF analysis also uses an excessive growth rate (5.25%) that outpaces the expected growth rate of the economy whose demands the Companies serve (4.70%). CCI Ex. 1.0 at 44. "Both practitioners and academics recognize that a long-term sustainable growth rate for use in a DCF model cannot exceed long-term projections of U.S. economic growth." CCI Ex. 1.0 at 44.

Mr. Moul's CAPM analysis also incorporates an improper leverage adjustment, applied in that analysis to the Companies' already (inconsistently) adjusted *Value Line* beta. CCI Ex. 1.0 at 47, 48; CCI Ex. 2.0 at 13: Table 2. The Companies' CAPM analysis is further corrupted by Mr. Moul's use of a market risk premium calculated as the average of a flawed historical estimate and a flawed prospective estimate. His historical risk premium selectively averaged historical returns during subjectively determined (and unexplained) periods described as having high or low interest rates. Mr. Moul's testimony does not provide details underlying the derivation of his projected market premium from unspecified S&P and *Value Line* data.

The Commission has routinely rejected reliance on Risk Premium analyses like that Mr. Moul offered:

> The Commission will not consider the results of the Companies' Risk Premium model that only the Companies have employed. We have repeatedly rejected this model as a valid basis on which to set return on equity. Our view remains unchanged.

Docket Nos. 09-0166/0167 (Consol.), Order at 128.

Because the Commission has consistently rejected the use of risk premium analyses, the Companies' Risk Premium analysis and estimate serve only to add a high-end data point, to increase the average of Mr. Moul's cost of equity estimates. Without this additional estimate, the average of Mr. Moul's estimates would decline by more than

60 basis points. The analysis also uses an arbitrary risk premium estimate that is not shown to be appropriate for the Companies. CCI Ex. 1.0 at 44.

Notwithstanding the Commission's routine rejection of Risk Premium analyses like that Mr. Moul offered, Mr. Moul criticized Mr. Gorman for not offering one. Although Mr. Gorman rejected this criticism, he also performed a balanced, reasonable risk premium analysis to demonstrate the unreasonableness of Mr. Moul's Risk Premium analysis result. CCI Ex. 2.0 at 1-2. Mr. Gorman's Risk Premium analysis yielded a return on equity range of 8.85%-9.50% with a midpoint of 9.15%. *Id.* at 28. This is substantially below Mr. Moul's Risk Premium equity return estimate of 10.39%. NS-PGL Ex. 19.0 at 25.

Mr. Moul also used the Comparable Earnings approach as a "check" on the results obtained using his other methods. PGL Ex. 3.0 at 3. However, for the reasons Mr. Gorman explains in his testimony, the comparable earnings approach does not accurately measure the required return for the investment risk of the Companies. *See* CCI Ex. 1.0 at 50-51.

Moreover, though Mr. Moul claimed to select companies using parameters that represent similar risk traits for the public utility and the selected comparable risk companies, Mr. Moul purposefully eliminated perhaps the most significant risk trait -- the regulated returns of public Companies. PGL Ex 3.0 at 36. All the companies in Mr. Moul's Comparable Earnings analysis are non-regulated. PGL Ex. 3.0 at 36. As Mr. Gorman noted, the fact that Companies are regulated is a key factor in S&P's rating of the business risk of public utilities as "Excellent." S&P states specifically:

> We view PGLC's business risk profile as excellent, reflecting our assessment of the regulated utility industry risk as 'very low' and a 'very low' country risk because the company's operations are based in the U.S.

CCI Ex. 1.0 at 7.

Furthermore, basing the allowed return for a regulated Illinois utility on a selection of unregulated companies, even as a "check," would violate the spirit, if not the express wording of Section 9-230 of the Illinois Public Utility Act. 220 ILCS 5/9-230. That provision is intended to preclude any distortion of a utility's rate of return by consideration of the risk of an unregulated enterprise -- in particular, affiliates. Although Mr. Moul does not use unregulated companies affiliated with the Companies, the distorting effect of these unregulated entities' business activity risks would affect the allowed return for regulated Companies.

Mr. Gorman recommends that the Commission determine that a 9.15% cost of common equity is reasonable and appropriate for setting the Companies' rates in this proceeding. Staff recommends a lower cost of equity (9.06%) that is comparable to Mr. Gorman's. In stark contrast to the Companies' inflated estimate (more than 100 basis points higher than any other in the record), the CCI and Staff recommended returns are mutually supporting. Eliminating Mr. Moul's inflating adjustments from the Companies' analyses would yield a return on equity in the range of 8.85% to 9.50%. That range encompasses both CCI's and Staff's recommended returns. CCI Ex. 1.0 at 37; Staff Ex.

3.0 at 2. For the reasons discussed, the Commission should adopt the Mr. Gorman's well-supported 9.15% cost of common equity for the Companies.

Commission Analysis and Conclusion

In determining the cost of equity the Commission is required to analyze the values derived from financial analysis tools commonly employed in making this determination. The parties presenting evidence on this issue are the Companies, Staff and CCI. Staff and CCI obtained similar results, the Companies numbers are substantially higher.

DCF analysis is a measure of the value of a company today, based on projections of how much money it's going to make in the future. Essentially the DCF value is the average of the present value of dividends plus a growth estimate for a group of similar companies. Individual analysts use different sources to find what they believe to be appropriate data based upon their backgrounds and experience.

Staff's expert, Ms Freetly, incorporated the dividend yield calculated by the Company expert at 4.00%. She then averaged projected earnings *per* share and dividends *per* share data for similar companies from four reporting sources including the Value Line projection relied upon by the Companies. This produced an average growth factor value of 4.82 %. Combining dividends and average growth projections produced a DCF value of 8.82%

CCI's expert began his cost of equity analysis with an assessment of utility industry investment risk, credit standing, and stock price performance. He concluded that the utility industry continues to be considered a safe-haven investment and that utility equity and debt investments are perceived as low-risk securities.

The CCI expert conducted three separate DCF analyses using: consensus analysts' growth projections, a sustainable growth estimate based on an internal growth methodology, and a multi-stage model that used near-term, transition, and long-term growth estimate inputs. His analysis of dividends and projected growth produced a value of 9.0%

The Companies expert on the other hand used a higher 5.25% growth factor reflecting "improving business conditions." The Commission also notes that this growth factor is higher than the 4.7% growth of the economy as a whole. Mr. Moul, the Companies' expert also used an upward "financial leverage adjustment" conflating book and market values to massage the DCF value in an upward direction. The Company derived DCF value was 9.71%.

The Companies have on many prior occasions attempted to convince the Commission that using a financial leverage adjustment to transform market to book value ratios is appropriate. This technique is produces a higher DCF value. The Commission has repeatedly rejected this manipulation:

> . . . the Commission does not agree that an adjustment to the market required return on common equity is necessary to reflect the difference in financial risk between book value and market value capital structures. Therefore, we reject the Companies' financial leverage adjustment to their DCF results

> and their proposal to impose a similar leveraging adjustment to the betas used in their CAPM analysis.

Docket Nos. 07-0241/0242 (Consol.), Order at 95-96; *See also* Docket Nos. 09-0166/09-0167 (Consol.), Order at 128-129.

CAPM Analysis

Another tool is CAPM analysis. The parties CAPM analysis produced values roughly consistent with their individual DCF results. CAPM determines an expected rate of return on a security by incorporating three variables: a) the risk-free rate of return; b) a "beta" that measures systematic risk; and c) the market risk premium.

For the risk free rate the Companies value was 4.25%, based on its expert's assessment of the midpoint of historical and forecast yields of 20 year treasury bonds. The Companies' inputs, at the very least, minimize the significance of the last several years of substantially lower interest rates that continue to be in effect at this time. For its beta measurement of systematic risk, the Companies employed the average Value Line beta for the Gas Group, "adjusted (upward) to reflect the application of this market-based measurement to the utility's book value capital structure used in ratemaking".

In other words, the two of the Companies' CAPM inputs are derived by selecting only higher interest rates and applying a Commission rejected leverage adjustment technique to the beta measurement. The Company also uses a risk premium value higher than Staff or CCI. Its bottom line CAPM number is 9.62%.

Staff's beta parameter averaged weekly *Value Line* betas with an average of monthly betas from *Zacks* and betas calculated using a regression analysis that the Commission has routinely adopted for the CAPM. These calculations produced a beta for the Delivery Group of 0.64. Staff points out that in the past the Commission has accepted Staff's beta number derived from several sources in order to reduce measurement error that might arise from a single source beta as proposed by the Companies.

For its risk-free rate parameter, Staff's expert, Ms. Freetly, used the 3.66% yield on thirty-year U.S. Treasury bonds on October 31, 2013. For the expected rate of return on the market parameter, Staff used a DCF analysis on the firms composing the S&P 500 Index generating an expected rate of return on the market of 12.43%. Inputting those three parameters into the CAPM, Staff's CAPM estimate of the cost of common equity for the Delivery Group is 9.27%

CCI's CAPM used Treasury bond returns as the risk-free rate, an average of historical and forward-looking market risk premium estimates, and the proxy group's average Value Line beta. The results of this analysis defined a cost of equity range with a midpoint of 9.24% rounded to 9.25%, almost identical to Staff's value.

The Commission finds that Staff's CAPM value of 9.27% is reasonable and supported by the record. The Commission finds that the Companies CAPM value is not appropriate.

Risk Premium Analysis

The Companies also uses a risk premium value that incorporates questionable assumptions. First, the Companies used historical and forecasted yields to estimate that the prospective yield on A rated corporate bonds should be 5.25% rather than the very recently observed rate of 4.54%. Their equity risk premium value of 6.25% represents the spread between common stocks in the S&P 500 and the yield on long term government bonds. Adding the two numbers produces a value of 11.50%.

Staff notes the S&P index is composed largely on non-rate regulated industrial concerns whose required rate of return exceeds the cost of equity for gas Companies. Staff argues against the use of the S&P 500 to estimate the expected return on equity for NS and PGL. The Companies are much lower risk companies than the overall market average. The risk premium for the overall market will be larger than that of an A-rated public utility, like NS and PGL. Therefore, adding that larger risk premium to the base bond return produces an overstated cost of equity estimate. The Companies' Mr. Moul effectively uses a cost of equity estimate for the overall market as an estimate for the lower risk NS and PGL.

Moreover, this Commission has routinely rejected risk premium analysis as a valid basis for determining return on equity. *See e.g.* Docket Nos. 09-0166/09-0167 (Consol.), Order at 128-129.. CCI argues that the Companies only use this Commission rejected technique to add a high-end data point, increasing the average of their cost of equity estimates.

The Companies also argued that comparable earnings of other companies could be used as a measure of required return. Unfortunately, the "comparable" companies used in their analysis don't include any other regulated Companies whose risk profile and earnings are lower than other types of businesses. The Commission finds this a comparison between apples and oranges.

The Commission finds that Staff's revised cost of common equity of 9.05% is reasonable and supported by evidence and analysis. The Commission notes that Staff's bottom line conclusion is supported by CCI's very similar determination, derived using the same methods with different inputs. The Commission rejects the Companies' significantly higher determination based in part on improperly biased input values and analytic tools that the Commission has repeatedly rejected.

F. Weighted Average Cost of Capital

Commission Analysis and Conclusion

Based on the evidence in the record and the applicable legal principles, the Commission approves as just and reasonable an overall rate of return (weighted average cost of capital) for North Shore of incorporating Staff's recommended capital structure and costs of short-term debt, long-term debt, and common equity, equals 6.26% for North Shore and 6.56% for Peoples Gas. The record consistently demonstrates that Staff's recommendations are based on valid application of sound financial theory, while the higher recommendations of the Companies are not.

North Shore Gas Company					
		Percent of		Weighted
	Amount	Total Capital	Cost	Cost
Long-term Debt	$79,784,000	38.94%	4.13%	1.61%
Short-term Debt	$21,678,000	10.58%	0.74%	0.08%
Common Equity	$103,435,000	50.48%	9.05%	4.57%
Total Capital	$204,897,000	100.00%		
Weighted Average Cost of Capital				**6.26%**

The Peoples Gas Light and Coke Company				
		Percent of		Weighted
	Amount	Total Capital	Cost	Cost
Long-term Debt	$864,589,000	46.51%	4.26%	1.98%
Short-term Debt	$58,805,000	3.16%	0.91%	0.03%
Common Equity	$935,610,000	50.33%	9.05%	4.55%
Total Capital	$1,859,004,000	100.00%		
Weighted Average Cost of Capital				**6.56%**

VII. OPERATIONS

A. AMRP Main Ranking Index and AG-Proposed Leak Metric(s)

Peoples Gas' Position

Peoples Gas states that the evidence establishes that: (1) Peoples Gas prudently uses its MRI to make decisions about which mains to replace; (2) the "peer group" analyses presented by AG witness Dr. Dismukes relating to replacement trends and leak trends are flawed; and (3) Dr. Dismukes' vague proposals to add one or more "performance metrics" related to leaks as conditions of recovery of costs of efforts to reduce leaks are not only unnecessary, but they could be counter-productive by diverting resources away from their best use.

Peoples Gas witness, David Lazzaro, an experienced engineer in replacing cast iron and ductile iron mains, explained that Peoples Gas utilizes criteria according to its MRI, which guides it in making appropriate decisions about targeting which mains to replace. Mr. Lazzaro discussed in detail the development and use of the MRI. He also described the processes for management oversight of the AMRP and coordinating with the City of Chicago.

Peoples Gas states that AG witness Dr. Dismukes suggested that one or more additional metrics related to leaks be adopted for the AMRP, but his proposals were vague and ill-conceived (not an accurate measure of the effectiveness of the AMRP), unnecessary given the current leak control measures in place, and, if adopted, could be counter-productive. Companies witness Mr. Lazzaro, in his rebuttal testimony, explained in detail why Dr. Dismukes' original proposal, of new metrics related to corrosion related leaks, was poorly designed and unnecessary, and why the MRI is what should continue to be used. Companies witness Mr. Lazzaro, in his surrebuttal testimony, explained in detail why Dr. Dismukes' vague rebuttal proposal, of new metrics related to a broader range of leaks, also was poorly designed and unnecessary, and why the MRI is what should continue to be used.

Peoples Gas states that adding new metrics, as AG witness Dr. Dismukes proposed, simply is a bad idea. As Companies witness Mr. Lazzaro explained:

> Q I mean, let's put it simply: Why don't you want to add those metrics as metrics for the program?
>
> A Well, we have currently in place procedures that grade and monitor the leaks that we have in our system, the ICC safety staff is aware of these pipeline safety staff is aware of these procedures and they audit the process annually, and opposed to any metrics that would take away the resources whether they're staff or dollars to focus on something that I don't think would help us with our replacement, considering we have the Main Replacement Program already.

Tr. at 130.

Peoples Gas states that the AG acknowledges that it has no objection in principle to Peoples Gas using the MRI. Further, the AG and its witness failed to identify anything in the MRI to which they object.

Peoples Gas contends that the AG's arguments in its briefs are devoted mostly to defending Dr. Dismukes' analyses, but provide essentially no factual support for his or the AG's vague proposals. The evidence does not provide any credible basis for rejecting the testimony of the Mr. Lazzaro, an experienced engineer, in favor of that of Dr. Dismukes, an economist, regarding whether new metrics should be adopted. Peoples Gas argues that the AG and Dr. Dismukes refer to cost recovery-related proposals adopted in three cases in New Jersey, but do not appear to advocate those same exact proposals here, do not show that circumstances are similar here, and provide no evidence that those proposals would be suitable, or cost-effective, as to Peoples Gas.

Peoples Gas concludes that the AG's vague proposals on this subject are ill advised and should not be adopted.

<u>AG's Position</u>

The AG explains that AG witness Mr. Dismukes prepared a series of analyses that examine Peoples Gas' historic pipeline replacement and leak trends, as well as a comparison of those trends to the midwestern LDC peer group. The purpose of Mr. Dismukes's leak analysis is to examine how effective, from an empirical perspective, Peoples Gas has been in replacing leak-prone or "priority" mains and services, as well as in reducing its corrosion-related leaks under its AMRP. His analysis expands upon the statistics discussed by PGL witness Lazzaro in his direct testimony. Mr. Dismukes' analysis of Peoples Gas' replacement and leak trends spans a relatively long time period, and includes the years in which Peoples Gas did not have an infrastructure replacement cost recovery mechanism, the years in which Rider ICR was in place, as well as those years after Rider ICR was reversed through a court appeal. Mr. Dismukes utilized data taken from PGL's annual reports filed with the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration ("PHMSA"), Office of Pipeline Safety ("OPS").

The AG states that the share of mains composed of cast iron fell by a few percentage points from 2009 to 2013, even as PGL's leaks have been rising over that time span.

Looking at historical replacement rates of leak-prone mains, Mr. Dismukes found that Peoples Gas' replacement rate of leak-prone main has decreased since 1991, on a relative basis. In fact, Peoples Gas' replacement rate reached its lowest relative level during the period 2009-2011, being 88 percent less than the replacement rate observed almost twenty years earlier. Meanwhile, midwestern LDCs, after an up-and-down trend (relative to 1991 levels) over the past two decades, have been replacing priority mains over the past two years at rates that are over 1.5 times their 1991 levels. Peoples Gas, on the other hand, while increasing its relative replacement rates over the past two years, has not done so at levels comparable to regional Companies.

Mr. Dismukes also found that, while a peer group of midwestern LDCs has attained a leak rate due to corrosion of around 50% or 60% of 1991 levels for the past decade-plus consistently, PGL's leak rate due to corrosion has been consistently (except for 2011) above the 1991 leak rate for the past seven years. Corrosion-related leaks are currently at levels that are 79 percent higher than those reported by Peoples Gas, on average, during the 1999-2006 period.

Mr. Dismukes recommended in direct testimony that given PGL's poor recent performance on reducing corrosion-related leaks, the Commission should consider adopting additional performance metrics that examine Peoples Gas' trends in reducing corrosion related leaks. Mr. Dismukes also pointed to several proceedings in the New Jersey Board of Public utilities ("NJBPU") wherein the NJBPU adopted leak performance metrics tied to a utility's allowed rates of return on infrastructure investment "trackers" or riders or tied the metrics to the allowance of recovery for the utility's leak-reduction efforts.

The AG submits that in rebuttal testimony, PGL witness Lazzaro argued that Mr. Dismukes should have addressed leaks with the seven other PHMSA leak cause codes (Natural Forces; Excavation Damage; Other Outside Force Damage; Material / Welds; Equipment; Incorrect Operations; Other). Mr. Lazzaro argued that following the new PHMSA regulations on Distribution Integrity Management Programs ("DIMP") issued in 2010 and enforced in 2011, Peoples Gas re-categorized many of its leaks as Corrosion related. Mr. Lazzaro did not explain, however, why the DIMP rule would not have affected other midwestern Companies similarly or why the increase in Corrosion-related leaks that Mr. Dismukes found began in 2007. Mr. Lazzaro argued that any performance metric for the AMRP should also consider Natural Forces- and Other-related leaks. He also argued that the MRI already used by Peoples Gas for prioritizing main replacements takes these three cause codes into account.

Mr. Dismukes expanded his leak analyses in his rebuttal testimony to consider the two additional PHMSA leak cause codes mentioned by Mr. Lazzaro. AG Exhibit 8.5 shows the results of his analysis on Natural Forces-related leaks, which increased substantially for PGL relative to peers from 2005, the first year data was collected for this leak category, through 2008. This category of leaks then began to decline for PGL until 2012, but then increased in 2013 to a level higher than any previous year. Meanwhile, the peer midwestern companies have consistently had leaks at similar levels since 2005.

AG Exhibit 8.6 shows the result of Mr. Dismukes' analysis on Other-classified leaks, which showed that PGL's Other leaks were relatively high in the 1990s, then dropped considerably in 1999 and 2000 and continued to decline since 2001, with a slight increase in 2013. This trend is similar to that of the regional Companies. The AG states that there is no evidence that leaks in the Natural Forces or Other categories were suddenly re-classified to the Corrosion category from 2011 onward.

The AG continues that there is no reason to think that the possible change in PHMSA reporting in 2011 had any material impact on Peoples Gas' overall leak trends, which Mr Dismukes found were still upward in recent years. AG Exhibit 8.7 shows Mr. Dismukes' study of a composite of Corrosion, Natural Forces, and Other leaks over 1991-2013. Peoples Gas' leaks across these three categories were relatively high in the 1990s, dropping significantly in 1998 and staying at similar levels until 2007 and 2008, when the Company experienced a significant relative increase in its composite leaks. The regional Companies also had relatively high leaks until 1997, when relative composite leaks started to decline and have remained fairly constant until 2009, when they again started to decline on a relative basis.

While the AG does not object in principle to PGL's use of its MRI, the Dismukes proposal goes beyond PGL's private, voluntary use of the MRI and requests that the Commission implement performance metrics that would be used as a basis for denying or allowing recovery of expense for leak reduction efforts, similar to the NJBPU case discussed at page 21 of Mr. Dismukes' direct testimony. The AG submits that the Commission could set performance metrics for leak reductions based on the recent trends observed in the midwestern peer group (for example, Peoples could be required to reduce its leaks with all three of the aforementioned cause codes to 50% of 1991 levels, as the peer group average has done for the past several years, as shown in AG Exhibit 8.7) and deny cost recovery for those leak reduction efforts to the extent that Peoples fails to meet the targets.

Commission Analysis and Conclusion

The Commission agrees with Peoples Gas and finds that the record does not support imposing any additional metrics on Peoples Gas' main replacement program, whether for operational purposes or as conditions of recovery of costs of leak reduction efforts. Peoples Gas provided evidence from an experienced engineer supporting the continued use of its MRI. The Commission finds that the evidence does not support the AG's proposals for new metrics and that their adoption would not prove useful and cost-effective enough for the Commission to impose them.

B. Pipeline Safety-Related Training (Uncontested)

The Companies and Staff agree that this Order should include a Findings and Ordering Paragraphs' paragraph that specifies, for Peoples Gas, the test year amounts of certain pipeline-safety related training. The agreed language is as follows:

> (x) The test year amounts of test year pipelines safety-related training for Peoples Gas are: $11,355 for Corrosion-NACE Levels 1 and 2 Certification; $80,500 for 49 CFR Parts 191 and 192 Training; $0 for Construction Inspection; $6,300 for all other pipeline safety-related training, totaling $98,135.

The agreed language is proper and it is incorporated in the Findings and Ordering Paragraphs section of this Order.

VIII. COST OF SERVICE

A. Overview

The Companies prepared embedded cost of service ("ECOS") studies to develop and implement their rate design proposals. With few exceptions, the Companies' ECOS studies are substantially identical to those presented, and approved by the Commission, in the Companies' recent rate cases. They slightly modified how they allocated Uncollectible Expense and the Miscellaneous Revenues in Account 495.

Staff states that the Companies' ECOS studies identify the revenues, costs, and profitability for each class of service and are a partial basis for the Companies' proposed rate design. Generally, the Companies prepared the ECOS studies utilizing three major steps: (1) cost functionalization; (2) cost classification; and (3) cost allocation of all the costs of the utility's system to customer classes. Staff witness Johnson testified that he had no objection to the Companies' proposed ECOS studies to assign costs to the various functions and rate classes.

AG/ELPC witness Scott Rubin recommended the Commission use the results of the Companies' ECOS studies as a guide to the allocation of costs among the customer classes and that the results of those studies should be used as a guide to designing rates.

IIEC witness Brian Collins takes issue with the Companies' proposed ECOS studies and proposes various adjustments.

B. Embedded Cost of Service Study

1. Allocation of Demand-Classified Transmission and Distribution Costs

<u>Companies' Position</u>

The Companies proposed to allocate demand-classified transmission and distribution ("T&D") costs using an average and peak ("A&P") methodology. The Companies assert that A&P is an accepted approach to such T&D cost allocation, and it is consistent with the Commission's orders in the Companies' five most recent rate cases. IIEC proposed a coincident peak ("CP") allocator for demand-classified T&D costs. Staff opposed IIEC's proposal and supported the A&P methodology. AG/ELPC opposed IIEC's proposal.

The Companies noted that IIEC is correct that they have supported a CP allocator for demand-classified T&D investment in past cases. However, the Companies explained that, in Docket Nos. 07-0241/07-0242 (Consol.), the Commission rejected that approach after considering arguments from the Companies and others supporting a CP allocator.

The Commission concluded that the Companies had not "overcome the Commission-established and long-standing tradition of A&P methodology for allocating distribution costs." Docket Nos. 07-0241/07-0242 (Consol.), Order at 199; also see NS-PGL Ex. 28.0 at 4. Subsequent to that case, to limit the scope of contested issues, the Companies have used the A&P allocator. The Companies further explained that the A&P allocator is recognized as an acceptable methodology for demand-classified costs. For example, the NARUC states at pages 27-28 of its Gas Distribution Rate Design Manual (June 1989) that the A&P demand allocation method is a commonly used demand allocator for natural gas distribution Companies and that this method tempers the apportionment of costs between the high and low load factor customers.

Staff's Position

Staff argues that the Commission should accept the Companies' proposed ECOS studies. These ECOS studies use largely the same cost allocation methodologies that were approved in the Companies' 2009, 2011, and 2012 rate cases. They are acceptable guidance for determining rates in this case.

Staff acknowledges that IIEC witness Collins disagrees with the Companies' proposed A&P cost allocation methodology for allocating T&D mains. He instead proposes that the CP cost allocation methodology be used. Mr. Collins provides two reasons why the A&P cost allocation method should be rejected. First, he states that the A&P cost allocation method double counts the "average" component of demand. Second, he opines that the A&P cost allocation method does not appropriately reflect how costs are incurred by the Companies.

Staff details that Companies Witness Hoffman Malueg explained that the Companies have been using the A&P allocation methodology since Docket No. 07-0241/07-0242 (Consol.). She also stated that while IIEC witness Collins continually asserts that the Companies' T&D system is designed to meet peak day demand, the Companies explained repeatedly in data responses to the IIEC that peak day demand, while being the primary factor, is not the only factor the Companies consider when designing the system. With respect to Mr. Collins' contention that the A&P allocator is double counting, Ms. Hoffman Malueg disagrees with this concept and states that demand costs are attributable to both average use as well as peak demand. To align with this theory, the A&P demand allocation method mathematically combines average usage and peak demand to appropriately allocate capacity costs based upon that cost causation method. Ms. Hoffman Malueg further explains that the A&P demand allocation method also mathematically weights the portion of the allocator that is to be based upon average demand by the system load factor, further aligning the theory that it is premised upon.

Staff witness Johnson explained that Mr. Collins' argument fails to recognize that the A&P allocator serves two distinct purposes, to reflect class contributions to the system average and to the system peak. Accordingly, the A&P appropriately considers both average and peak demands in the allocation process.

Staff continues that the Commission addressed this double counting argument by the IIEC in Docket No. 04-0476, Illinois Power Company's proposed general increase in natural gas rates. The Commission concluded that:

> While the IIEC argues that the A&P method improperly double counts average demand in allocating T&D plant costs, the Commission believes that when allocating T&D plant costs an emphasis on average demand is appropriate. The record demonstrates that the A&P method relies upon class average demands and class coincident peak demands, which by definition are numerically larger than the associated averages.

Illinois Power Company, Docket No. 04-0476, Order at 64-65 (May 17, 2005).

Additionally, in Central Illinois Public Service ("CIPS") and Union Electric ("UE") proposed general increase in natural gas rates, the Commission stated:

> Furthermore, the Commission finds that the argument that the A&P method double counts average demand is not a sufficient basis for rejecting that approach. In fact, the Commission believes that when allocating demand costs it is the A&P method's emphasis on average costs rather than peak costs that justifies its adoption.

Central Illinois Public Service Company (AmerenCIPS) and Union Electric Company (AmerenUE), Docket Nos. 02-0798/03-0008/03-0009 (Consol.), Order at 98 (October 22, 2003).

In response to Mr. Collins' argument that the A&P cost allocation method does not appropriately reflect how costs are incurred by the Companies, Mr. Johnson explained that the A&P allocates costs by both peak demands and average demands. The peak demand component recognizes that a T&D system is sized to meet maximum annual demands. However, there is also an average demand component because meeting peak demands is not the sole factor that shapes investment in a T&D system. Another factor, but not the only factor, is the economic motivation to construct a T&D system. This is more appropriately reflected by average demands than peak demands. This is because year-round demands are necessary to generate sufficient revenues to justify investment in a T&D system. These year-round demands are reflected in the average demand but not the peak demand portion of the A&P allocator.

Staff adds that other factors are safety and reliability. Safety and reliability investments are more appropriately reflected in average demands. Safety and reliability are important, not just only for the peak day, but for every day of the year that gas is consumed which is what the average demand component reflects.

Staff notes additionally that there is strong precedent in Illinois for using the A&P demand allocator. The Commission typically uses this allocation methodology for the distribution costs of gas companies. In CIPS and UE's proposed general increase in natural gas rates, Docket No. 04-0476, the Commission concluded:

> The allocation method that properly weights peak demand is the A&P method, the same method that the Commission adopted in CIPS' and UE's last gas rate cases. The A&P method properly emphasizes the average component to reflect the role of year-round demands in shaping transmission and distribution investments.

Docket Nos. 02-0798/03-0008/03-0009 (Consol.), Order at 98.

Staff states that the Commission also accepted the use of the A&P allocation methodology in Nicor Gas' 2004 rate case. *Northern Illinois Gas Company*, Docket No. 04-0779, Order at 102 (September 20, 2005) and Nicor Gas' most recent rate case Docket No. 08-0363. The Commission subsequently directed Peoples Gas and North Shore to employ the A&P demand allocation methodology to allocate the distribution costs in Docket Nos. 07-0241/07-0242 (Consol.). Docket Nos. 07-0241/07-0242 (Consol.), Order at 199. Since then, the Companies have employed the A&P demand allocation methodology in their COS studies. In each case, the A&P methodology was approved by the Commission.

Staff notes that AG/ELPC witness Rubin also disagrees with IIEC's proposal to eliminate the A&P allocator. Mr. Rubin indicated his understanding that the Commission has used the A&P method consistently for the Companies since at least 2007, and IIEC witness Collins does not present any new arguments or a compelling reason to change this well-established allocation method. Mr. Rubin also reviewed the rebuttal testimony of Companies' witness Hoffman Malueg and agrees with her criticisms of Mr. Collins' testimony on this issue and concluded that IIEC failed to show that the Companies' use of the average and peak method is improper.

<u>IIEC's Position</u>

IIEC argues that the ECOS studies proposed by the Companies are flawed because they allocate the demand classified T&D costs (both rate base and expenses) using the A&P allocation method which allocates costs in part by using a volumetric allocation factor (average demand) and fails to recognize a customer component for any portions of its main costs. The Companies support their choice of the A&P method not because it is superior or more respected than the CP method; rather, the Companies use the A&P method in hopes to limit the contested issues in this proceeding. IIEC notes too that the Companies have previously recommended that capacity related T&D system costs be allocated using the CP method in Docket Nos. 07-0241/07-0242 (Consol.). Docket Nos. 07-0241/07-0242 (Consol.), Order at 199. IIEC asserts that the Companies have not presented any technical evidence that supports the use of the A&P method for allocating the Companies' capacity related T&D system costs.

IIEC argues that although the Commission has previously approved the A&P method for the Companies, the Commission has also approved the use of the CP method for allocating capacity or demand related T&D costs in previous Companies' rate cases, notably Docket No. 90-0007 and Docket No. 91-0586. In fact, the Commission Staff supported the CP allocation method in Docket No. 90-0007. IIEC maintains that because the Commission and its Staff have previously shown support for allocating demand related T&D costs on the CP method, there is no clear precedent for the A&P cost allocation method. Determining whether a cost allocation method is appropriate should be based on the evidentiary record in the instant proceeding. While it is true that this Commission has previously approved the use of the A&P method, the Commission is not bound by its prior determinations assuming there is sufficient evidence in the record to support the adoption of a new position, or in this case an old position, by the Commission. *Mississippi River Fuel Corp. v. Commerce Comm'n*, 1 Ill. 2d 509, 116 N.E. 2d 394, 396-397 (1953). IIEC asserts that the record in the instant proceeding provides information not previously available to the Commission in prior rate cases when determining the appropriateness of the CP cost allocation method for the Companies' systems. IIEC states that the evidentiary record in the instant proceeding supports the use of the CP method for allocating T&D system capacity or demand costs. The CP allocator matches the classes' system peak capacity required on the system peak day with the costs incurred by the Company to meet those classes' peak day demands, thus best reflecting cost causation.

IIEC states that the record contains: (1) a detailed explanation and illustration of how the A&P double counts average demand and the resulting detrimental effects to both residential non-heating and large volume users; (2) an illustration of how the A&P allocation factors result in unbalanced cost allocation to the classes; and (3) an illustration of how the A&P allocation factors, when applied to the Companies' system peak day capacity, result in capacity shortfalls for certain classes.

First, IIEC states that a significant issue with the A&P demand allocator is the fact that it double counts the "average" component of demand. Average Demand is counted twice in the allocation of demand costs, once in the coincident peak allocation and then again in the average demand allocation. The double counting results in an over-allocation of costs to higher load factor customers such as residential non-heating customers and industrial customers.

IIEC explains that there are two steps in the process of calculating the A&P factors for the customer classes. The first step determines the average demand component. The second step determines each class's contribution to the system's peak demand. It is in the second step where the double counting takes place. Double counting occurs because the A&P method considers both the average demand and the entire peak demand, which also includes average demand.

IIEC states that because class average demand constitutes a larger percentage of the coincident demand for high load factor customers it adversely affects the S.C. 4 class more than any other class. For PGL, class average demand constitutes 34% of coincident demand for the S.C. 4 class, versus 23% or less for the other classes. For NS, class average demand constitutes 60% of the coincident demand for the S.C. 4 class, versus 23% or less for the other classes.

IIEC continues that the A&P method double counts the service classes' contributions to average demand, and the Companies' method in this case is no exception. Ms. Hoffman Malueg argues that simply because average demand values are smaller than coincident peak demand values that should not imply that the Average and Peak demand allocation method should be discredited because it is 'double counting'.

IIEC responds that Mr. Collins does not argue that average demand is double counted because average demand is smaller than coincident peak demand. Mr. Collins argues that average demand is double counted by the A&P cost allocation formula because average demand is a subset of demand contained within coincident peak demand.

Average demand is a subset of coincident peak demand, where Coincident Peak Demand can be expressed as Coincident Peak Demand = (Average Demand + Peak Demand in Excess of Average). Said simply, the A&P cost allocation formula double counts average demand because average demand is weighted by the system load factor, and then weighted again by (1 - the system load factor) because Average Demand is a subset of Coincident Peak Demand. By using the A&P demand allocation methodology to allocate capacity costs to customer classes, average demand is always given 100% weight in the capacity allocation factor regardless of the system load factor.

IIEC adds that average demand is given considerably more weight in the allocation of T&D capacity cost than are coincident peak demands, which are the primary load characteristic that explains cost causation. The result of double counting Average Demand is that Average Demand will always be given 100% weight in the A&P demand allocation formula despite the fact that Average Demand is not considered in the design of the Companies T&D system capacity. It is peak demand in excess of average that drives the capacity of the T&D systems needed to meet the coincident peak day demands of the Companies' customers. IIEC argues that the CP method is appropriate because it reflects how the T&D system is designed and therefore reflects cost causation.

Second, IIEC maintains that coincident demand best reflects cost causation. IIEC explains that Gas distribution T&D systems are designed based on the design day demand or the coincident peak demand requirements of its customers. The design of the system allows the Companies to offer firm uninterrupted service to all customers every day of the year, including the day the system peak day demand occurs. IIEC asserts that average demand is not a factor in the design of the system as confirmed by the Companies in their response to IIEC Data Requests 6.01 and 6.12. If the Companies designed their systems based on average day demands then it would not be guaranteed the Companies would have adequate capacity to meet the customers' coincident demands on the system peak day.

IIEC continues that while average demand is certainly a factor considered in identifying the variable cost of operating the system, the actual physical size of the T&D mains, compressors, and related equipment is based on customers' contributions to the system peak day demand. Further, average demands do not describe the main size or system capacity that is necessary to provide firm uninterruptible supply of service to all customers every day of the year. The system's capacity must be sized for peak day demand, assuring all customers utilization of their entitlement to that capacity to receive firm, uninterrupted, supply of gas every day of the year, including the day of the peak demand.

Based upon this, IIEC argues that the Companies' proposal fails to meet the cost of service principle of cost causation. The Companies state the most important principle underlying an ECOS study is that cost incurrence should follow cost causation. Therefore, according to the IIEC, the A&P method is inappropriate for ratemaking in this proceeding because it does not appropriately reflect how the costs associated with T&D mains, including both rate base and expenses, are incurred by the Companies. As a result, the A&P allocation method creates an unbalanced allocation of T&D costs among customer classes.

As an illustration of such unbalanced cost allocation resulting from the A&P method, IIEC witness Collins focused on distribution main costs. Distribution main capacity allows customers that need firm service to receive firm service every day of the year, including the day of peak demand. As such, customers need an amount of capacity entitlement equal to their coincident peak day demand that allows them to receive firm service every day of the year. IIEC adds that the actual usage of this capacity entitlement throughout the year then is a function of the customers' load factor.

IIEC explains that the A&P method assigns a significantly different distribution main net plant cost per unit of coincident demand to each customer class, even though all classes have equal rights to firm distribution capacity on the system peak demand day. The per unit cost for distribution main net plant is significantly higher for the Companies' higher load factor customers, specifically the Non-Heating S.C. 1 Residential and S.C. 4 Large Volume Demand Service, than it is for low load factor customers. IIEC argues that under the A&P allocation method, customer classes that more efficiently utilize the T&D system are allocated a premium, on a per unit of coincident demand basis, for distribution main net plant in their rates as compared to lower load factor customer classes.

IIEC states that the above illustration also demonstrates the tempering that Ms. Hoffman Malueg refers to when she explains that the A&P demand cost allocation methodology provides "compromise" and "tempers" cost apportionment between high load factor and low load factor customers. Such temperament allocates a higher per unit cost for distribution main net plant to the high load factor customers than it does the low load factor customers. IIEC maintains that the A&P method misassigns cost to the high load factor customers that should be assigned to low load factor customers under proper cost-causation principles. However, when costs are assigned to the classes using the CP method, all classes are allocated the same per unit cost of distribution main net plant, resulting in a balanced allocation of costs.

IIEC submits that with the A&P cost allocation method, costs are shifted between classes based on load factor, or how they utilize the system peak day capacity. By introducing load factor and volume into the cost allocation process, the A&P method results in rate impact mitigation by misallocating costs in the cost allocation process. IIEC argues that rate impact mitigation should not occur in an ECOS study. A proper ECOS study should properly measure each class's cost causation. The CP method measures costs appropriately because it is based on cost causation. After costs are allocated to classes using a proper ECOS study, rate impact mitigation is then best addressed through revenue allocation and rate design.

IIEC offers that another illustration of how the A&P allocation method does not properly allocate T&D main capacity costs across customer classes is to compare the A&P allocation of the total system peak day capacity to each class, with the amount of actual capacity that is needed by each class on the coincident peak day. The illustration shows the residential non-heating and Large Volume Demand classes are over allocated system capacity using the A&P allocation method. As a result, the Non-Heating S.C. 1 Residential and S.C. 4 Large Volume Demand customers subsidize the cost of capacity to other classes that have a shortfall in capacity needed on the Companies' system to meet their peak day demand requirements. However, when system peak day capacity is allocated to classes based on the CP method, all classes are allocated enough system peak day capacity to meet their coincident peak day demands. IIEC states that in the case of PGL, use of the A&P allocator allocates 11% more capacity to the Non-Heating S.C. 1 Residential class and the S.C. 4 Large Volume Demand Service class than is necessary to meet their peak day demands. In the case of NS, use of the A&P allocator allocates 8.8% to the Non-Heating S.C. 1 Residential class and 34.6% to the S.C. 4 Large Volume Demand Service, again in excess of what is necessary to meet their peak day demands.

Third, IIEC states that a proper cost allocation method should reflect how costs are actually incurred on the Companies' T&D systems. IIEC argues that a utility's selection of a particular cost allocation method should be based on whether that allocation method appropriately reflects class cost causation and results in rates that provide accurate price signals to its customers.

IIEC emphasizes that the most important principle underlying an ECOS study is that cost incurrence should follow cost causation. Because rates should reflect cost causation, the costs used in setting rates should be allocated to classes based on how the classes cause the costs to be incurred by the Companies. IIEC asserts that the cost allocation method should be consistent with cost causation.

IIEC maintains that T&D systems are designed to meet the demands of customers and not their gas throughputs or usages; therefore, allocating the costs of the T&D system based on demand is appropriate. Further, a utility's T&D main investments must meet its customers' demands and a utility incurs the cost to construct and operate T&D mains to meet its customers' peak day demands. This is exactly why IIEC witness Collins believes the CP method is an appropriate cost allocation method for allocating T&D related capital costs and expenses, because the CP method allocates costs based on how they are incurred, using customer peak demands and not annual throughput.

IIEC states further that allocating costs based on how they are incurred is consistent with the NARUC Gas Distribution Rate Design Manual (June 1989) which states at page 20:

> Historic or embedded cost of service studies attempt to apportion total costs to the various customer classes in a manner consistent with the incurrence of those costs. This apportionment must be based on the fashion in which the utility's system, facilities and personnel operate to provide the service.

IIEC Ex. 1.0 at 15-16.

NARUC recognizes that demand or capacity related costs can be allocated to classes based on two factors: (i) peak day demands, and (ii) the number of customers.

The NARUC Gas Distribution Rate Design Manual states the following at pages 23 and 24:

> Demand or capacity costs vary with the size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of the distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size.

Id. at 16.

IIEC notes that the Companies cite the NARUC Manual as well in support for their use of the A&P method stating the Manual finds the Companies' allocation method provides compromise and tempers cost apportionment. But the Companies fail to cite further support in the Manual for their use of the allocation method while IIEC states that it cites language from the Manual supporting its position on use of an allocation factor that accurately reflects cost causation. IIEC argues while the Companies' proposed A&P method is one found and used in the Manual, their additional support for its use is tepid at best.

IIEC contends that it is the peak day demand which drives the costs incurred in order to design, construct, implement and maintain a T&D system that is adequate to provide firm service throughout the year, including the peak day, to all customers that want firm service. T&D systems are sized based on peak day demands to ensure that firm gas supply can be delivered every day of the year and because cost causation is driven by peak demand, T&D related costs should be allocated based on peak demand. IIEC claims that as the NARUC manual correctly observes demand and capacity costs vary with the size of plant and equipment and do not vary with annual usage. Therefore, they should not be allocated on the basis of a method that considers average demand or volume.

IIEC states that if the T&D system can meet the peak day demand of its customers it stands to reason it can meet the demand of its customers on every single day of the year. The only way daily needs can be met is through a system that is designed to meet the peak day demand. If the peak day demand can be met, all daily demands will be met as well.

IIEC states that in Docket Nos. 07-0241/07-0242 (Consol.), the Companies advocated for the use of the CP method to allocate T&D mains to customer classes. The Companies' witness Ronald J. Amen found the CP method to be the most appropriate indicator of cost causation and argued against the use of the A&P method.

IIEC argues that using the A&P allocation method to allocate capacity related costs based on perceived benefits resulting from year round use of the Companies' T&D

systems is not based on cost causative factors. Benefits are in the eye of the beholder as there are not objective measures to define or determine to what extent particular customers derived such benefits. In stark contrast, cost-causation is based on the T&D system's engineering and an understanding of the drivers that determine a utility's costs. IIEC concludes that the Coincident Demand allocation method best represents cost causation on the Companies' T&D systems.

Commission Analysis and Conclusion

The Commission agrees with the Utilities and finds that although both the CP and the A&P method are acceptable ways to allocate demand-classified T&D costs, the A&P method of cost allocation is supported by the record and consistent with the method of allocation adopted in previous rate cases. The Commission holds that IIEC has not shown that the CP method is preferable in this case. The Commission finds that the Utilities' use of the A&P method for demand-classified T&D costs is reasonable and is approved.

2. Allocation of Small Diameter Main Service Costs

Companies' Position

The Companies assert that they do not delineate between small and large diameter distribution mains in their ECOS studies, nor is it appropriate to do so. The Companies explained, and it is undisputed, that all of the Companies' customers take service from all the various sized mains in the system. Specifically, except for Peoples Gas' negotiated contract rates (S.C. Nos. 5, Contract Service for Electric Generation, and 7, Contract Service to Prevent Bypass), all service classifications take service directly from mains smaller than four inches and from mains that are four inches and larger. Moreover, the Companies stated that they operate their systems in an integrated manner, which enhances system reliability for all customers. The Companies explained that their ECOS studies have a class-based structure. That is, the Companies allocate costs to the customer classes and not individual customers or *ad hoc* groups within the classes. For the Companies, the customer classes are the service classifications and rate groups within the service classifications for which the Companies design rates.

The Companies state that IIEC's proposal to consider moving the three customers taking service directly from smaller diameter mains to another service class is flawed because these customers do not qualify for S.C. No. 2, which is available only to customers using a monthly average of 41,000 therms or less. None of the three customers are eligible for S.C. No. 2 and all are properly on S.C. No. 4.

The Companies' witness Ms. Hoffman Malueg explained that selectively allocating only certain main costs to S.C. No. 4 is incompatible with the class-based nature of the ECOS studies. The Companies' ECOS studies allocate costs to the customer classes (S.C. No. 4 is such a class), based on class characteristics and not based on individual customer characteristics or *ad hoc* group characteristics within the classes. The number of customers taking service from various main sizes in a given class is irrelevant. Ms. Hoffman Malueg explained that the ECOS studies are not intended to extract for or allocate specific costs to individual customers.

The Companies claim that they do not allocate distribution mains to customer classes within their ECOS studies based on customer counts. The fact that there are only three S.C. No. 4 customers out of 180 (total within both Companies) taking service directly from a main smaller than four inches has no relevance in the ECOS studies. They argue that IIEC apparently seeks only to look at customer counts as relevant for S.C. No. 4 for certain mains, but, if customer counts are appropriate for S.C. No. 4 and for certain size mains, does fairness dictate that customer counts become a factor for all size mains and other facilities, for all service classifications? The Companies state that making a single, selective exception to the class-based nature of the ECOS studies may be feasible, but it is not feasible to begin making exceptions for all particular costs that may fit IIEC's theory.

Staff's Position

Staff explains that IIEC witness Brian Collins proposes to delineate the costs of mains smaller than 4 inches and allocate those costs to all classes except for the S.C. No. 4 class. He states that because all but three S.C. No. 4 customers do not utilize mains smaller than 4 inches in receiving service, this adjustment reflects cost causation.

Staff continues that the Companies' engineering witnesses, David Lazzaro and Mark Kinzle respectively stated that smaller diameter mains support service to the S.C. No. 4 customers. In fact, the Companies design and operate their systems in an integrated manner. The fact that a customer is directly served by a main that is four-inches, or greater, does not mean that smaller diameter pipe is not useful, or in some instances, necessary, in serving that customer. Staff maintains that operating the system as an integrated whole enhances the reliability of service to all customers. For example, smaller diameter mains may backfeed the larger diameter main and support service to the S.C. No. 4 customer. A backfeed refers to an alternate flow path for the gas. Staff states that this may be important when an outage occurs, resulting from, for example, required maintenance activity or third party damage to the Companies' facilities.

Staff adds that Companies witness Hoffman Malueg states that all service classifications portrayed in the Companies' ECOS studies receive service directly from all sizes of distribution mains. The only purpose of delineating between small and large distribution mains within the Companies' ECOS studies would be to segregate costs such that they can be allocated to the service classifications differently. However, because all of the Companies' service classifications are served from all sizes of distribution mains, there is no reason to delineate distribution mains within the ECOS studies. Additionally, the Companies' witnesses Mr. David Lazzaro and Mr. Mark Kinzle within their rebuttal testimonies explain that the Companies' distribution systems are an integrated network of various main sizes. Staff reasons that simply because a customer is directly served by a large distribution main does not preclude the fact that a small distribution main is useful in providing service to such customer. Given these reasons, Staff asserts that it is not appropriate to delineate between small and large distribution mains within the Companies' ECOS studies.

Staff mentions as well that AG/ELPC witness Rubin also addressed this issue and disagreed with the IIEC's proposal. Mr. Rubin stated that the IIEC ignores the fact that customers in the S.C. No. 4 class are served by mains in the 4 inch and smaller category, as the Companies indicated in several data request responses. Mr. Rubin opined that there was no factual support for IIEC's position on this issue.

IIEC's Position

IIEC argues that another flaw in the Companies' cost of service study is the Companies' failure to distinguish between small and large distribution mains. IIEC proposes to delineate the costs of the mains smaller than 4 inches and allocate those costs to all classes except for the S.C. 4 class.

IIEC states that the Companies do not delineate between small and large distribution mains and argue that because all of the Companies' service classifications are served from all sizes of distribution mains, there is no reason to delineate distribution mains within the ECOS studies. IIEC witness Collins argues this is not true. The Companies' system of mains is akin to the branches of a tree; the gas flows from the largest diameter mains into successively smaller sizes of mains. Large volume customers cannot be served by the smaller diameter mains, because mains with small diameters simply do not have sufficient capacity to supply those customers' needs.

IIEC maintains that its interest in this issue lies in the fact that only 3 customers out of 180 customers in the Companies' S.C. No. 4 class are served by mains less than four inches. The Companies' cost of service studies show net plant balances of $1.03 billion for PGL and $117 million for NS in FERC Account 376 - Distribution Mains. These plant balances include the cost of all distribution mains regardless of their diameter and the costs in these balances are distributed to all service classes on the basis of the inferior A&P allocation factors. IIEC reasons that in distributing main costs in such a manner the Companies' cost of service studies allocate the cost of 2-inch and 3-inch mains to customers that bear no responsibility for the Companies' investment in those mains, ignoring the principles of cost causation. It is not appropriate to allocate the costs of mains smaller than 4 inches serving only 3 S.C. No. 4 customers based on the combined load characteristics of all 180 S.C. No. 4 customers to the entire S.C. No. 4 rate class. Under such circumstances the cost of small mains should be delineated and those costs assigned to the customer classes other than S.C. No. 4.

IIEC states that the Companies' claim that smaller mains do in fact support the Companies' service to S.C. No. 4 customers. The Companies' witnesses argue the Companies design their systems in an integrated manner and the fact that a customer is directly served by a main that is four inches or greater does not mean that smaller diameter pipe is not useful and, in some instances, necessary, in serving that customer. They cite an example of this small diameter pipe's usefulness by suggesting the smaller diameter mains may backfeed the larger diameter main and support service to the S.C. No. 4 customer.

IIEC argues that Companies witnesses Mr. Lazzaro and Mr. Kinzle failed to support their backfeeding arguments with any credible examples of the actual necessity or the feasibility of such backfeed. In order to replace gas from larger pipes, the smaller diameter pipes would have to operate at a greater pressure than normal operating pressure to accommodate the increased volumes as a result of any such backfeed. IIEC maintains that due to the safety concerns, it is unlikely that backfeeding can occur in all circumstances or for long periods of time.

IIEC submits that neither Mr. Lazzaro nor Mr. Kinzle responded to Mr. Collins' question of safety or feasibility in their surrebuttal testimony. Neither witness provided any detail as to how often the smaller diameter mains are used to backfeed larger pipes that serve S.C. No. 4 customers or for what periods of time the smaller diameter mains can be safely used to backfeed. Neither witness indicates whether backfeeding has occurred on the system peak day. Finally, while backfeeding may be an ancillary service provided by the smaller diameter mains, backfeeding does not reflect normal operation of the system and is not mentioned by the Companies as a consideration in designing the T&D systems. IIEC claims that the arguments of the Company witnesses do not provide justification for allocation of 4-inch main cost to the S.C. No. 4 class.

IIEC notes that Company witness Hoffman Malueg argues the 3 S.C. No. 4 customers taking service from smaller mains ought not to receive a different cost of service than the other 177 S.C. No. 4 customers, nor should all the S.C. No. 4 customers receive no allocation of smaller diameter main costs when some customers (3 of 180) directly receive service from those mains. Ms. Hoffman Malueg further argues Mr. Collins' proposal is a selective exception to the class-based nature of the ECOS studies and not feasible to begin making exceptions for particular costs.

IIEC reiterates that only 3 customers out of 180 customers in Companies' S.C. No. 4 class are served by mains less than four inches. IIEC proposed in its rebuttal testimony that the Companies move the 3 customers who receive service from mains smaller than 4 inches to another service class if in fact those customers do not meet the qualification for service under the S.C. 4 tariff. If this were done, there would be no customer in the S.C. No. 4 class served by 4 inch mains and reallocation of those costs to other rate classes would be appropriate. In the alternative, the Companies should directly allocate the specific smaller than 4 inch main related costs used to serve these 3 customers to the entire S.C. 4 class. IIEC maintains that from a cost causation standpoint, either of these approaches is more appropriate than the Companies' proposal to allocate all mains smaller than 4 inches based on the combined load characteristics of all 180 customers in the S.C. No. 4 class.

IIEC submits that despite the protest of feasibility, identifying and allocating these costs is possible, especially in light of the fact there are only 3 S.C. No. 4 customers served by small mains. In fact, other Companies do directly allocate the costs of mains smaller than 4 inches used to serve a small number of its largest customers. IIEC concludes that Mr. Collins' adjustments to the allocation of small mains should be adopted.

<u>Commission Analysis and Conclusion</u>

The Commission agrees with the Utilities and finds that selective exceptions to the class-based nature of the ECOS studies are not appropriate in this instance. Customers in all the service classes (except for certain Peoples Gas negotiated rate customers) take service from all the different sized mains on the Utilities' systems. The ECOS studies are not intended to extract for or allocate specific costs to individual customers. Delineating mains by size within the ECOS study would be inconsistent with this approach, no matter how implemented. The Commission finds that the Utilities' decisions not to make delineations in their ECOS studies based on main diameter are reasonable.

IX. RATE DESIGN

A. Overview

Companies' Position

The Companies prepared ECOS studies to develop and implement their rate design proposals. NS Ex. 14.0; NS Exs. 14.1-14.8; PGL Ex. 14.0; PGL Exs. 14.1-14.8. The Companies assert that with few exceptions, the Companies' ECOS studies are substantially identical to those presented in the Companies' recent rate cases. *Id.* They have slightly modified how they allocated Uncollectible Expense (NS Ex. 14.0 at 17-18; PGL Ex. 14.0 at 18-19) and the Miscellaneous Revenues in Account 495 (NS Ex. 14.0 at 21-22; PGL Ex. 14.0 at 22-23).

The Companies' witness Ms. Egelhoff testified that the proposed rate designs were intended to and would accomplish the following six major objectives: (1) recover the revenue requirement, (2) better align rates and revenues with underlying costs, (3) send proper price signals regarding the costs recovered through the rates, (4) provide more equity between and within rate classes, (5) reflect gradualism considering test year revenue requirements, and (6) address the S.C. No. 2 distribution block structure and sizes. NS Ex. 15.0 at 6; PGL Ex. 15.0 REV. at 6.

Staff's Position

The Companies propose greater recovery of fixed costs through fixed charges. The Companies consider all of their costs recovered through base rates as fixed. Peoples Gas' classes are S.C. No. 1 Residential Heating and Non-Heating, S.C. No. 2 General Service, S.C. No. 4 Large Volume Demand Service, S.C. No. 5 Contract service for electric generation, S.C. No. 7 Contract service to prevent bypass, and S.C. No. 8 Compressed Natural Gas Service. North Shore's classes are the same as Peoples Gas except North Shore does not have a No. 8 Compressed Natural Gas Service class. The Companies also propose changes to various miscellaneous charges.

Staff recommends the Commission: (1) begin the process of adjusting the Companies' rate designs away from a straight fixed variable ("SFV") based rate design for the S.C. No. 1 Residential Heating and Non-Heating classes and the S.C. No. 2 General Service class; (2) accept the Companies' proposed rate design for Peoples Gas and North Shore's S.C. No. 4 Large Volume Demand Service rate class; (3) accept the Company's proposed rate design for Peoples Gas' S.C. No. 8 Compressed Natural Gas Service; and (4) accept the Companies' proposed Service Activation Charges, Reconnection Charges, and Second Pulse Data Capability Charges. Staff Ex. 4.0 at 4-5.

AG's Position

In their last distribution rate cases (Docket Nos. 12-0511/12-0512 (Consol.)), PGL and NS proposed to establish separate rates and customer classes for residential heating and non-heating customers, which was approved by the Commission. The proposal stemmed from the Commission's order in the Companies' 2011 cases that required the Companies to prepare cost-of-service studies that separated low-use residential customers from higher-use residential customers. AG/ELPC Ex. 3.0 at 6.

The result of separating heating and non-heating customers into different classes was a substantial reduction in the bills for non-heating customers, due to the significantly lower demand-related costs of serving those customers. The increases in Heating customers' customer charges that flowed out of the Heating/Non-Heating bifurcation, however, have been unnecessarily and inequitably amplified by the Companies' obsessive march toward increasing the amount of revenues recovered through the fixed customer charge. For example, Peoples Gas and North Shore residential heating customer charges have risen by nearly 200% and 179%, respectively, since 2007, the year PGL/NS began filing a steady stream of rate cases under its then new parent company, Integrys Energy Group. In fact, the Companies filed five rate cases over a seven-year period in their quest to increase profits and achieve the goal of maximum recovery of revenues through the customer charge. In 2007, the PGL customer charge was $9.00. Today for heating customers it stands at $26.91. In this case, Peoples Gas seeks to increase that charge another 43%, to a proposed $38.50. For North Shore customers, customer charge rates have increased from $8.50 in 2007 to the current $23.75. North Shore seeks to increase that charge another 24%, to a proposed $29.55 for heating customers.

Back in 2007, PGL and NS recovered, respectively, 27% and 28% of the residential revenue requirement through the customer charge, with variable *per* therm charges covering the remainder of the delivery service portion of the bill. In that year, PGL's flat monthly charge for both heating and non-heating customers was $9.00. *See* Docket Nos. 07-0241/07-0242 (Consol.), Schedule *E-2*, page 10 of 371. Today, it is $26.91 for heating customers. For North Shore, the residential customer charge was $8.50 in 2007 for both heating and non-heating customers. *See Docket No. 07-0241, North Shore Gas Co. – Proposed Increase in Delivery Service Rates*, Schedule E-2, page 8 of 261. Today it is set at $23.75 for heating customers. The bottom line is that Peoples Gas and North Shore customers pay the highest rates in the state – both in terms of the customer charge and *per* therm charges. PGL's and NS's extraordinary request to seek 43% and 24% increases in the Residential Heating customer charge, respectively, threatens to exacerbate that reality.

High customer charges mean the Companies' lowest users bear the brunt of rate increases, and subsidize the highest energy users. The Companies' claims that all costs are fixed is belied by their own cost studies, which identify significant operational costs as tied to demand of natural gas. Steadily increasing customer charges diminish the incentives to engage in conservation and energy efficiency because a smaller portion of the bill is subject to variable usage charges and customer efforts to reduce usage. AG/ELPC Ex. 3.0 at 15, 20-21.

The Commission should reject the Companies' unsupported claim that customer charges must be raised to ensure cost recovery. AG witness Rubin's proposed rate design (1) corrects the inequitable cross-subsidization of high users by low users of natural gas that occur when more and more costs are recovered through the flat customer charge; (2) reflects the Companies' minimal risk of recovering their authorized revenue requirement in light of the guaranteed revenue recovery that the Companies enjoy through decoupling, uncollectibles and infrastructure riders; and (3) furthers the public policy goals of promoting energy efficiency and conservation through higher variable charges. It should be adopted by the Commission.

ELPC Position

The ELPC intervened in this case in order to address one important issue, Peoples Gas' proposal to increase its fixed monthly charge for residential heating customers by 43.1%. The Commission should reject this proposal because it sends customers the wrong price signals regarding energy efficiency and it reduces customers' benefits from efficiency. While ELPC acknowledges that the Company should recover some of its fixed costs through fixed charges, the current allocation ratio already allows the Company to recover an adequate percentage. This issue has sparked ongoing debate in Illinois, but the Commission succinctly addressed the issue in a recent 2013 report to the General Assembly that recommends shifting revenues out of the fixed charges back in the variable charges. As set forth below, the evidence in this docket supports those findings.

City-CUB's Position

The Companies have made efforts to increase their fixed cost recovery by increasing the customer charge in each of their last four rate proceedings. *See* Docket Nos. 12-0511/12-0512 (Consol.), Order at 227; Docket Nos. 11-0280/11-0281 (Consol.), Order at 188 ("The trend in the Companies last three rate cases has been to request substantial increases in the customer charge, which may impact low use customers in excess of their cost of service or their contribution to demand-related costs."). Peoples Gas currently recovers about 55% of total base rate revenues from fixed charges, (PGL Ex. 15.0 at 11), and North Shore Gas currently recovers about 67% of total base rate revenues through fixed customer charges, (NS Ex. 15.0 at 11). The Companies' proposed rate designs in this proceeding continue their incessant campaign to move toward greater fixed cost recovery. The Companies propose to recover 90% of non-storage related fixed costs through the customer charge for residential non-heating customers (S.C. No. 1 NH) for both Companies, (NS Ex. 15.0 at 11; PGL Ex. 15.0 at 11), and for residential heating customers the Companies' proposed rate designs would allow NS to recover 80% and PGL 75% of their designated (non-storage related) "fixed costs" through fixed monthly charges. PGL-NS Ex. 29.0 at 4.

The Companies' proposal departs from recent decisions by the Commission that rejected proposals to move further toward an SFV rate design through increased customer charges. *See, e.g. Commonwealth Edison Co.*, Docket No. 13-0387, Order at 75 (Dec. 18, 2013); *Ameren Illinois Co*., Docket No. 13-0476, Order at 101-102 (March 19, 2014).

Instead of seeking to increase the fixed charges that customers face, the Commission's ComEd RDI Order stated its policy support for correctly returning to cost-causation based rate design. Both Staff and AG/ELPC witnesses oppose the Companies' continued pursuit of a self-serving SFV design.

CUB/City recommend that the Commission adopt the AG/ELPC proposed rate design that allocates any revenue requirement increase to the S.C. No. 1 volumetric charges and caps the customer charge at the current percentage of revenues, for both heating and non-heating customers.

B. General Rate Design

1. Allocation of Rate Increase

Companies' Position

The Companies used their ECOS studies to allocate revenue requirements and develop rates. As in prior cases, the Companies set cost-based rates for each service classification. The Companies stated that their ECOS studies and the descriptions of their rate designs are detailed and specific enough that it would be straightforward to derive rates from the revenue requirements the Commission approves. IIEC proposed an "across-the-board" increase (IIEC Ex. 1.0 at 24), *i.e.*, each service classification should receive the same percentage of the revenue deficiency as the overall system deficiency, regardless of what the ECOS studies show. The Companies opposed IIEC's proposal for several reasons.

First, the Companies stated that the premise for IIEC's allocation proposal is its two proposed changes to the Companies' ECOS studies. The Commission should reject both proposals. Second, the Companies claim that IIEC has failed to provide support for an across-the-board increase or to address how these resulting costs should be used to set rates and that the IIEC has failed to offer any rates and bill impacts that would result if such an allocation were approved. In addition, the proposal would not result in cost-based rates for any service classification and would create cross-subsidization across service classifications. NS-PGL Ex. 29.0 REV at 21-22. Third, despite IIEC's citing the importance of cost causation in the ECOS studies, the Companies stated that it is incongruous for IIEC to ignore the ECOS studies to design rates. Fourth, the Companies argued that the Ameren case cited by IIEC does not support its proposal. In *Central Illinois Light Company d/b/a AmerenCILCO, et al.*, Docket Nos. 07-0585 et al., Order (Sept. 24, 2008), the Commission approved an across-the-board increase because of the unique circumstances of that electric utility's transition from a legislatively mandated rate freeze. The Commission stated that it was "reluctant to return to full cost based rates after less than one year. The rate shock that would result from returning to full cost based rates would likely lead to another redesign docket." The Commission further stated that it "certainly does not mean to suggest by this decision that cost based rates have fallen out of favor. Indeed, cost based rates, as we affirmed in our recent decision in Docket No. 07-0566, continue to be the Commission's preferred rate design methodology." AmerenCILCO at 280.

Staff's Position

The Companies state that if the Commission approves a revenue requirement other than that proposed by the Companies, they will make the necessary adjustments to the appropriate ECOS studies' accounts and allocators based on the findings in the Commission order in this proceeding. Assuming that the Commission approves the Companies' proposed rate design, the resulting allocation of the revenue requirement by rate and customer class from the ECOS studies will then be used to set charges as discussed in the direct testimony of Companies witness Egelhoff and by using the formulas reflected in the supporting rate design work papers. Staff Ex. 4.0 at 25.

Staff has no objection to the Companies' proposal to re-run the ECOS studies and adjust the rate design based upon the Commission's final Order. *Id.* The IIEC states that due to the flaws in the Companies' cost of service studies, it proposes an across the board increase. IIEC Ex. 1.0 at 24.

The Companies disagree with IIEC's proposed across the board increase. The Companies state that they primarily base their rate design on the ECOS study. NS-PGL Ex. 29.0 REV at 21. Mr. Collins states that this across-the-board approach is supported by the modified cost of service studies sponsored by his colleague, Ms. Amanda M. Alderson. IIEC Ex. 1.0 at 25. However, these cost of service studies contradict Mr. Collins' argument for an across-the-board increase because they show that each service class causes different allocations of the proposed revenue deficiencies.

<u>AG's Position</u>

AG/ELPC witness Rubin dismisses IIEC's proposed across-the-board increase. Mr. Rubin states the IIEC witness Collins is the only witness who recommended any changes in the study. His changes are not appropriate, as they are neither supported by the facts nor consistent with the Commission's standard practice. Moreover, even if one of his recommendations were properly supported, that does not render the study itself to be flawed. AG/ELPC Ex. 9.0 at 13. The AG/ELPC also stated that another IIEC witness (Ms. Alderson in IIEC Exhibit 2.0) had no trouble using the Companies' cost models to produce new results using Mr. Collins's assumptions. Thus, there is no basis for concluding that the Companies' cost-of service studies are "flawed" or unable to be modified to produce reliable results. *Id.*

<u>IIEC's Position</u>

IIEC is recommending an across-the-board increase for PGL and NS. Each service classification should receive the same percentage of revenue deficiency as the overall system deficiency shown for each Company, respectively, regardless of what the Companies' ECOS studies show as the revenue deficiency for each individual service classification. IIEC Ex. 1.0 at 24. Based on the results of the modified Companies' cost of service studies performed by IIEC witness Alderson (IIEC Ex. 2.1) using the CP allocation for T&D related capacity costs as well as utilizing the small mains adjustment, an across-the-board increase is reasonable and results in moderate increases for all classes.

The Companies contend that allocating the same revenue deficiency to each service classification gives no regard to the results of the ECOS studies, which provide the portrayal of cost causation by service classification. NS-PGL Ex. 28.0 at 12. However, IIEC has shown how the Companies' ECOS study results are flawed and while the Companies may claim they "portray" cost causation, IIEC has illustrated how they in fact do not assign costs in a cost causative manner. The system average increase is appropriate when a cost study is flawed and does not provide reliable results. IIEC Ex. 3.0 at 17.

Alternatively, if the Commission does not approve of an across the board increase for all Peoples' rate classes, the IIEC supports a revenue allocation for Peoples based on the results of IIEC's cost of service study that includes both the CP allocation of demand costs and the small mains adjustment shown in IIEC Ex. 2.1. This would result in the S.C. 1 class receiving 82% of the system average increase approved by the Commission for Peoples. The S.C. 2, S.C. 4, and S.C. 8 classes would receive approximately 138%, 118%, and -78% of the system average increase approved by the Commission, respectively. IIEC continues to recommend a system average increase for NS's rate classes.

An Across-the-Board Increase Supports the Principle of Gradualism

Comparing the results of the IIEC modified Companies' cost of service studies presented in IIEC Exhibit 2.1 to an across-the-board increase, shows an across-the-board increase is reasonable because it results in moderate increases for all classes. IIEC Ex. 3.1. Reflecting gradualism prevents any one class from experiencing rate shock.

Gradualism reflects a gradual change in rates to move toward cost of service over time, as opposed to drastic changes in rates to move immediately to cost of service. IIEC Ex. 3.0 at 18.

Company witness Egelhoff argues that IIEC fails to provide support for an across-the-board increase or address how the resulting costs should be used to set rates. NS-PGL Ex. 29.0 at 21. As stated previously, the system average increase is appropriate when a cost study is flawed and does not provide reliable results. IIEC Ex. 3.0 at 17. An across-the-board approach has previously been approved by the Commission in Docket No. 07-0585 in which the Commission granted Ameren Illinois Companies an across-the-board increase for both electric and gas rates. *Id.* at 18.

Companies' witness Hoffman Malueg argues in addition to failing to provide evidentiary support for an across-the-board increase, Mr. Collins failed to consider the impacts upon cost classifications within the ECOSSs, which in turn would have impacts upon rate design. NS-PGL Ex. 28.0 at 252-254. However, IIEC has considered that fact and would expect that the resulting revenue allocation from an across-the-board increase by rate and customer class would be used to set the charges using the Companies' proposed rate design formula. IIEC Ex. 3.0 at 18-19. IIEC argues the Company would have to use the same process to design rates under its proposal as it would if the Commission approves rate increases to the classes that differ from the Companies' proposal.

Commission Analysis and Conclusion

The Commission rejects both of IIEC's proposed changes to the ECOS studies, and that makes IIEC's rate allocation proposal moot.

In addition, the cost of service studies contradict Mr. Collins' argument for an across-the-board increase. They show that each service class causes different allocations of the proposed revenue deficiencies. The Commission finds that IIEC has failed to provide adequate support for an across-the-board increase. Its proposal would not result in cost-based rates for any service classification and would create cross-subsidization across service classifications. The proposal fails to address how his proposal would impact the recovery of cost based storage costs recovered under Rider SSC, Storage Service Charge, as well as the determination of baseline uncollectible amounts by service classification that are reconciled under Rider UEA.

2. Fixed Cost Recovery

Companies' Position

The principal rate design issue in this case is the type of charge -- fixed or volumetric -- through which the Utilities should recover non-storage demand-classified distribution costs. The Companies contend that their proposals strike an appropriate balance between recovering all fixed costs in fixed charges, which is driven by the fact that fixed costs do not vary with gas use, and moving gradually to such a rate design, recognizing that the Companies' Rider VBA, addresses the inevitable over- and under-recovery that results from recovering fixed costs in variable charges. NS-PGL IB at 123-127.

Staff and intervenors advocate placing more fixed cost recovery in variable charges as a "traditional" rate design, citing recent electric utility orders as support for moving more fixed cost recovery to variable charges, arguing that their rate designs promote energy efficiency. They also cite certain of the Companies' riders as a reason to have less fixed cost recovery in fixed charges, and claim that the Companies' rates result in low use Service Classification ("S.C.") No. 1, Small Residential Service, customers subsidizing high use S.C. No. 1 customers.

The Companies noted that Staff and intervenors refer to "SFV" rate design repeatedly. The Companies explained that SFV is merely a term describing a rate design under which all fixed costs are recovered in fixed charges. NS Ex. 15.0 at 13; PGL Ex. 15.0 REV. at 13. Contrary to at least one intervenor's claims (City/CUB IB at 7), the Companies have not proposed an SFV rate design, nor are their current rates based on an SFV rate design. NS-PGL Ex. 29.0 REV. at 4. The Companies' witness Ms. Egelhoff did state that, absent the Companies' decoupling mechanism (Rider VBA), which is under Illinois Supreme Court review, SFV is the appropriate rate design. NS Ex. 15.0 at 13; PGL Ex. 15.0 REV. at 13. An SFV rate design is not before the Commission in this case.

Demand Costs Are Fixed Costs

The Companies explained that demand-classified costs (*e.g.*, storage, land, structures and improvements, mains, compressor station equipment and measuring and regulating equipment) are fixed costs. The costs of this type of investment do not vary with customer usage or even if the customer's demand day requirements change. NS PGL Ex. 43.0 REV. at 4. When North Shore or Peoples Gas installs a main to serve a residential customer, the cost of that main, included in setting the revenue requirement that will underlie rates in this 2015 test year case, will not change from day-to-day or year-to-year simply because the customer uses more or less gas on the peak day or any other day. *Id.* at 5-6. The Companies contrasted the demand costs with, for example, the quantity of gas that the Companies purchase to serve customers, which does vary with usage. For demand costs, the amount included in base rates in the test year is the same whether a customer consumes 0 therms or 100 therms and will not change even if the customer class' peak day usage increases or decreases. *Id.* The Companies acknowledged that the way to recover demand costs is often contested, but, citing an authoritative NARUC source, the costs are clearly fixed. NS-PGL Ex. 29.0 REV. at 8.

The Companies also explained that the example of the demand of different size homes does not support Staff's and intervenors' arguments. There is no support for their premise that the cost of the main is different because a customer's home is 1,000 square feet and another customer's home is 4,000 square feet. The costs incurred to serve a community containing either size home would be comparable. In the example given and considering not just a single home but a community with like-sized homes, the same size main and services would be used to supply each community. The Companies' explained that the size of the service and the cost to install would be the same for both size homes. NS-PGL Ex. 38.0 at 8; NS-PGL Ex. 45.0 at 4.

The Companies posited that the question is, in the absence of a demand charge, whether to recover these fixed costs in a customer charge, a distribution charge, or both. (The Companies noted that a demand charge would be a way to recover demand costs. However, Staff, confusingly, refers to "distribution\demand charges." Staff IB at 95, 100. They are not the same. NS-PGL Ex. 29.0 REV. at 14.) The Companies' rate design, in this and prior cases, generally recovers the demand costs in both fixed and variable charges, with gradual movement towards placing recovery of these fixed costs in fixed charges. *See, e.g.*, NS Ex. 15.0 at 11, 16; PGL Ex. 15.0 REV. at 11, 16. The problem with Staff and intervenor proposals to place all S.C. No. 1 demand costs in variable charges is that it necessarily presumes that usage affects demand costs. (Staff also makes proposals for other service classifications that stem from the same arguments.) It is correct that system peak day usage drives the size of demand-related infrastructure (NS-PGL Ex. 29.0 REV. at 7), but it is false that day-to-day usage causes any change to these costs. Under the Staff and intervenor proposals, when a customer uses more gas -- on a peak or other day -- he pays more towards demand costs, and when he uses less gas, he pays less towards demand costs. Yet, the same main or regulator is still in base rates and still supporting service to that customer. *Id.* at 7-8. For these reasons, for a rate class that does not include a demand charge, a fixed charge, like the customer charge, is a much better cost causal rate design than a variable charge, like the distribution charge.

Energy Efficiency

Companies' witness Ms. Egelhoff stated that one of the Companies' rate design objectives is to send proper price signals regarding the costs that are the subject of the rates being set in these cases. They achieve this by proposing to move more fixed cost recovery into fixed charges. The price signal conveyed to customers is the cost to serve them, *i.e.*, how much gas the customer uses does not affect the cost to deliver gas to that customer. The Companies contrast this accurate price signal with the erroneous price signals that the Staff and intervenor proposals would send, namely that the more gas customers use the more it costs the Companies to provide them delivery service. Stated differently, Staff and intervenor proposals falsely tell customers that lower usage reduces the Companies' costs to provide delivery service. NS-PGL Ex. 29.0 REV. at 3-4. The Companies contend that the purpose of rate design is not to manipulate customer behavior but, inter alia, to recover the revenue requirement and better align rates and revenues with underlying costs.

Ms. Egelhoff explained that energy efficiency is addressed through other means. The Companies' energy efficiency programs, under Section 8-104 of the Act and that the Commission most recently approved in Docket No. 13-0550 and before that in Docket No. 10-0564, are designed to achieve statutorily-required energy efficiency goals, through customer participation in the approved programs. Ms. Egelhoff stated that the Commission approved a budget and the Companies recover the costs of their programs under their Rider EOA, Energy Efficiency and On-Bill Financing Adjustment. The Illinois General Assembly and the Commission intend that costs related to conservation and energy efficiency measures occur within the context of the Companies' approved Section 8-104 plans and not through rate design that sends incorrect price signals. NS-PGL Ex. 29.0 REV. at 10. Through the Section 8-104 programs and providing for volumetric cost recovery under Rider EOA, the Commission provided a clear signal as to how the Companies are to implement and recover costs for their energy efficiency programs. The Companies' gas distribution service to residential customers in single family homes and multi-family buildings is entirely driven by fixed costs. The mere presence of the customer for a particular account drives the nature of the cost of the utility service (*e.g.*, the meter and main) to that premises. NS-PGL Ex. 29.0 REV. at 11.

The Companies also showed that customers have ample incentives to reduce gas use. Under their proposals, a large portion of a typical S.C. No. 1 heating customer's annual bill before taxes would be derived from variable charges such as supply and distribution (approximately 60% for Peoples Gas and 70% for North Shore). *Id.* at 9. Also, under any rate design, gas costs remain one of the largest portions of an average residential heating customer's annual bill, with the cost of gas constituting approximately 40% for Peoples Gas and 55% for North Shore. NS-PGL Ex. 29.0 REV. at 9-10. The Companies cited the Commission's conclusions in a Nicor Gas case, "[t]he portion of fixed costs that are currently recovered through a volumetric charge are in fact fixed costs, and thus cannot be conserved. Moving a greater percentage of fixed cost recovery to fixed charges rather than volumetric charges provides a more stable revenue stream and sends a better price signal to the consumer." *Northern Illinois Gas Company d/b/a Nicor Gas Company*, Docket No. 08-0363, Order at 91 (Mar. 25, 2009).

Rider Mechanisms

The Companies acknowledged that the various riders that Staff and intervenors cited provide stability for customers and the Companies. For example, Rider VBA is a rate design mechanism designed to prevent over- or under-recovery of the Companies' Commission-approved revenue requirement. Docket Nos. 11-0280/11-0281 (Consol.), Order at 163. Rider UEA, Uncollectible Expense Adjustment, is designed to provide recovery (not over- or under-) of the Companies' uncollectible amount (bad debt). 220 ILCS 5/19-145. Rider SSC, Storage Service Charge, does the same for base rate storage costs and was needed to support unbundling that the Commission required for certain transportation programs. Docket Nos. 11-0280/11-0281 (Consol.), Order at 229. However, these mechanisms do not support rates that are not founded on sound cost causation principles. They are not (contrary to Staff's analogy (Staff IB at 100)) comparable to EIMA. Rider VBA, for example, does not provide for the recovery of any costs outside of the approved revenue requirement, nor does it allow adjustments based on actual costs being more or less than the approved revenue requirement. Under EIMA, the reconciliation is far more than a simple true-up of amounts billed to customers to an approved revenue requirement. EIMA looks at all actual non-fuel costs in its reconciliation. With some limits, the EIMA process takes into account higher or lower costs. NS-PGL Ex. 29.0 REV. at 6. Movement away from fixed cost recovery in fixed charges thus has much less of an effect on the electric Companies' ability, under EIMA, to recover its revenue requirement than it does on gas Companies.

Low Use/High Use Customers

The AG argues that the Companies' rate design proposals would create intra-class subsidies (with low use customers subsidizing high use customers) and are unfair to low income customers. AG IB at 83-84, 92-97. The Companies contend that the AG arguments fail for two fundamental reasons. NS-PGL RB at 108-110.

First, the cross-subsidization argument is premised on not recognizing that demand costs are fixed costs. Indeed, the Staff and intervenor proposals could result in high use customers subsidizing low use customers. NS-PGL Ex. 43.0 REV. at 9.

Second, the AG equates low use customers with low income customers and their arguments are predicated on taking general data about the city, county, state or other region and applying it to the Companies' customer bases to categorize customers as low income. Neither the Companies nor the AG have income information about the Companies' customers. The AG witness used general data to draw conclusions, and tried to explain away utility data that were contrary to his theory. The Companies only have Low Income Home Energy Assistance Program ("LIHEAP") and percentage of Income Payment Program ("PIPP") customer-specific data to identify North Shore's and Peoples Gas' low income customers. The data Peoples Gas provided AG witness Mr. Colton show that an average Peoples Gas low income (*i.e.*, LIHEAP and PIPP) S.C. No. 1 heating customer uses more (not less) gas than the typical such customer (1,258.60 therms versus 1,066.62 therms). NS-PGL Ex. 29.0 REV. at 22, 24. The AG witness tried to dismiss these data by saying they were a function of what he considers the Companies' inappropriate definition of low income customers. AG Ex. 4.0C at 11; AG Ex. 10.0 at 9-10. The AG's witness ignored the customer-specific data Peoples Gas provided, which contradicted his theory that low income customers are low use customers, and instead claimed the data were flawed because they did not use his definition of low income. NS-PGL Ex. 43.0 REV. at 11.

The Companies responded to the Commission's concerns about distinguishing low use and high use residential customers by proposing S.C. No. 1 non-heating (sometimes identified by "NH") and heating (sometimes identified by "HTG"), which the Commission approved. S.C. No. 1 NH rates accurately reflect the lower costs of serving these lower use customers who place less demand on the system. The Companies do not have service classifications based on customer's income, nor do they agree that subsidizing low use customers on the premise that it may be beneficial to low income and elderly customers is a sound rate design. However, low income customers' needs are addressed through targeted assistance programs that are available irrespective of a customer's usage levels. Even low income customers with higher than average use may be eligible for assistance. The Companies also offer energy efficiency programs and on-bill financing programs to all customers, encouraging them to adopt energy efficiency measures and practices. NS-PGL Ex. 29.0 REV. at 23.

The Companies' S.C. No. 1 rate design takes low use and high use customers into account through the heating and non-heating rate design. The fact that the bill impacts, in percentage terms, are higher for low use customers than for high use customers is not evidence of inappropriate intra-class subsidies, but rather is evidence of simple mathematics: the percentage effect of an increase in the fixed customer charge will be greater for a low use customer, compared with a high use customer, because the increase is applied to a smaller bill.

Staff's Position

The Commission should accept Staff's and the AG's recommendation to begin moving away from SFV-based rate design. The Commission's recent Orders in ComEd (Docket No. 13-0387) and Ameren Illinois (Docket No. 13-0476) make it clear that SFV-based rate designs should be re-examined and rate design should reflect traditional rate design principles, which more closely align customers' bills with the ECOS study. The Commission is actively reevaluating how rate design can be utilized to ensure that customers are responsible for the demands they place on the system and that rate design maximizes conservation efforts.

Staff witness Johnson explained that traditionally, rate design aligned customer charges with the ECOS study customer costs and aligned *per* therm distribution charges with the ECOS study demand costs. Staff Ex. 4.0 at 20. The Companies' proposals to increase fixed cost recovery through fixed charges (NS Ex. 15.0 at 9 and PGL Ex. 15.0 REV at 9) is a SFV-based or modified SFV rate design that shifts recovery of some of the ECOS study demand related costs to the customer charge and away from the *per* therm distribution charge. The result reduces the effect of increased usage on the customers' bill. When a customer charge is based upon all of the ECOS study customer costs and part of the ECOS study demand costs, the resulting *per* therm distribution charge is lower than it would have been if all demand costs were recovered through the distribution charge. The Companies' rate design can encourage increased consumption through lower *per* therm distribution charges rather than discouraging it through higher *per* therm distribution charges. Thus, the price signal for ratepayers to conserve is weakened. Staff Ex. 4.0 at 20.

Staff witness Johnson recommends the Commission move away from a SFV-based rate design. In Docket No. 13-0387, the Commission adopted adjustments to ComEd's SFV-based rate design in Docket No. 13-0387, which moved away from SFV-based rate design through lower fixed cost recovery. Staff Ex. 4.0 at 16. The rate design the Commission approved in the ComEd case set customer charges based upon the ECOS study's customer costs and demand charges based upon the ECOS study's demand costs. Docket No. 13-0387, Order at 68.

Additionally, in Ameren Illinois Company's ("Ameren") most recent revenue neutral electric rate design case (Docket No. 13-0476) the Commission directed Ameren to maintain the current percentage of fixed cost recovery through fixed charges (44.8%) for the DS 1 residential class, even though the Company requested an increase to 50% fixed cost recovery through a modified SFV rate design, with the expectation that the issue would be revisited in Ameren's next rate design proceeding.

One of the main drivers the Commission noted behind its rejection of the AG's proposal to move away from SFV-based rates and significantly reduce the fixed cost recovery through fixed charges in the Ameren case was the potential to create rate shock for a significant number of electric space heating customers. While such concerns could have been addressed by a phased-in approach, the record was insufficient to implement such an approach. Therefore, the Commission did not adopt the AG's proposal, yet still rejected Ameren's proposal to increase fixed cost recovery through fixed charges in its proposed modified SFV rate design. Docket No. 13-0476, Order at 102.

The Commission subsequently granted rehearing in Docket 13-0476 to provide the Commission with additional evidence about the bill impacts of moving away from an SFV rate design for residential customers. Ameren Illinois proposed adopting a SFV rate design for the DS-1 class customer charge to recover 44.8% of the DS-1 revenue requirement from the monthly non-volumetric charges. The AG proposed a rate design through which the Company would recover approximately 28% of its revenue requirement through the non-volumetric charges. Docket No. 13-0476, Order on Rehearing at 40 (September 30, 2014). The Commission reiterated its support for a discontinuation of the shift toward a greater SFV rate structure:

The Commission ultimately accepted Staff's proposal that continues the movement away from a SFV rate design and shifts to a rate design that decreases the fixed customer charge and increases the variable charges, while protecting against the potential for significant bill impacts, as initially contemplated in the original Docket No. 13-0476 March 19th Order. Docket No. 13-0476, Order on Rehearing at 42.

These recent Commission orders adopt rate designs that move away from a SFV-based rate design and instead align customers' bills with the cost of service (*i.e.*, customer charges based upon ECOS study customer costs and distribution/demand charges based upon ECOS study demand costs). *Id.* at 19. It is clear the Commission is considering how rate design can be utilized to ensure that customers are responsible for the demands they place on the system and that rate design maximizes conservation efforts. Additionally, the Commission is weighing the effects of the EIMA on revenue stability in the electric industry and the gradualism needed in adjusting SFV-based rate design because of potential rate shock. *Id.*

Peoples Gas and North Shore have implemented Rider VBA which stabilizes the distribution revenue requirement approved by the Commission in the Company's most recent rate proceeding. Peoples Gas has also implemented Rider QIP, which allows the Company to recover a return on, and depreciation expense related to, the Company's investment in qualifying plant because the Company's last rate case. Peoples Gas, ILL.C.C. No. 28, Sheet No. 130-138.2. Both of these riders are rate recovery mechanisms that mitigate concerns regarding revenue stability. *Id.* at 19-20.

The Companies' ECOS studies take functional costs and further classify them by cost causation into commodity related, demand related, and customer related. Each class is then assigned commodity, demand, and customer related costs. Adoption of the Companies' rate design would create inconsistency between how costs are caused and how revenues are collected. For example, the Companies' proposed SFV-based rate design recovers some demand related costs, such as distribution mains, through the customer charge and therefore shifts cost recovery from a *per* therm basis to a *per* customer basis. Staff Ex. 4.0 at 21. The inconsistency arises because assigning demand related costs to the customer charge assumes each customer in the class contributes equally to the class demand. There is no evidence in the record to support this assumption. Furthermore, that assumption is inconsistent with the way demand costs are allocated among the customer classes. Demand related costs are allocated among customer classes based on demand, not based upon the assumption that each customer contributes equally to demand.

AG/ELPC witness Rubin also recommends that the Commission reject the Companies' proposals to move closer to straight fixed-variable rate design. He states that moving towards SFV rate design would create inequities and cross-subsidies within the residential space heating class. He also concludes that SFV rate design is unnecessary, given the use of other rate mechanisms to achieve revenue stability, and that it is contrary to the State's energy efficiency policies. AG/ELPC Ex. 3.0 at 3.

The Companies' responded that all of their costs (ECOS study customer and demand costs) are fixed and that fixed costs should be recovered through the customer charge for S.C. No. 1 and S.C. No. 2 classes. Companies' witness Egelhoff states that the Commission has endorsed policies in several rate proceedings to increase the fixed cost recovery through fixed charges. With respect to demand costs alone, Ms. Egelhoff states that demand costs, by definition, are driven by customer demand on the peak day. NS-PGL Ex. 29.0 REV at 7. The infrastructure that is put in place to handle the demand will cost the same regardless of the amount of demand that is placed on the system at any given time. *Id.* at 8.

Ms. Egelhoff's statement misses the point. The relevant question here is not the cost of the infrastructure built to meet demand but rather who should pay for it. If demand costs are recovered through the customer charge, all customers are assumed to cost the same for the Companies to serve them. Staff Ex. 9.0 at 7. If demand costs are recovered through the distribution charge, the recovery method assumes the costs are not the same for all customers to serve them. If demand costs are recovered through the distribution charge, that assumes that customers with higher usage will have higher peak demands and be more costly to serve than small use customers. While this latter assumption may not be true in each and every case, it is more reasonable than the Companies' proposed rate design's implied assumption that all customers within a class cause the utility to incur the same amount of demand costs.

Staff also observed that the Companies' approach does not encourage conservation as much as Staff's rate design, which recovers a greater share of costs through variable charges and thereby increases the financial incentive for customers to adopt conservation measures. Although gas costs comprise a portion of a customer's total monthly gas bill, the customer is still concerned about the total bill. Recovering distribution demand costs on a *per* therm basis increases the incentive to conserve. In contrast, the Companies' rate design recovers some of the demand costs on a *per* customer basis instead of a *per* therm basis. This causes the distribution charge to be lower compared to if all of the demand costs were recovered on a *per* therm basis. Thus, the price signal for ratepayers to conserve is weakened. Staff Ex. 9.0 at 8.

A recent ruling by the 2nd Circuit Court of Appeals upheld a Commission tariff that permitted Peoples and North Shore Gas to reconcile over or under recovery of revenues resulting from deliveries being higher or lower than anticipated. The result of this ruling is that the Commission can provide a mechanism for revenue stability that lowers the monthly customer charges and increases the volumetric charges. Such a change can decrease energy use by providing a greater price signal without affecting the overall bill to an average retail customer.

The Commission has recognized that lower monthly customer charges and higher volumetric charges *(per* therm distribution charge) can decrease energy use by providing a greater price signal. Staff's rate design proposal, which lowers the customer charge and increases the volumetric charge compared to the Companies' proposals, encourages energy conservation to a greater extent than the Companies' proposal would. *Id.*

<u>AG's Position</u>

In their last distribution rate cases (Docket Nos. 12-0511/12-0512 (Consol.)), PGL and NS proposed to establish separate rates and customer classes for residential heating and non-heating customers, which was approved by the Commission. The proposal stemmed from the Commission's order in the Companies' 2011 cases that required the Companies to prepare cost-of-service studies that separated low-use residential customers from higher-use residential customers. AG/ELPC Ex. 3.0 at 6.

The result of separating heating and non-heating customers into different classes was a substantial reduction in the bills for non-heating customers, due to the significantly lower demand-related costs of serving those customers. The increases in Heating customers' customer charges that flowed out of the Heating/Non-Heating bifurcation, however, have been unnecessarily and inequitably amplified by the Companies' obsessive march toward increasing the amount of revenues recovered through the fixed customer charge. For example, Peoples Gas and North Shore residential heating customer charges have risen by nearly 200% and 179%, respectively, since 2007, the year PGL/NS began filing a steady stream of rate cases under its then new parent company, Integrys Energy Group. In fact, the Companies filed five rate cases over a seven-year period in their quest to increase profits and achieve the goal of maximum recovery of revenues through the customer charge. In 2007, the PGL customer charge was $9.00. Today it stands at $26.91. In this case, Peoples Gas seeks to increase that charge another 43%, to a proposed $38.50. For North Shore customers, customer charge rates have increased from $8.50 in 2007 to the current $23.75. North Shore seeks to increase that charge another 24%, to a proposed $29.55.AG/ELPC Ex. 3.0 at 25.

Back in 2007, PGL and NS recovered, respectively, 27% and 28% of the residential revenue requirement through the customer charge, with variable *per* therm charges covering the remainder of the delivery service portion of the bill. In that year, PGL's flat monthly charge for both heating and non-heating customers was $9.00. *See Docket No. 07-0242, Peoples Gas Light & Coke Co.* – Proposed Increase in Delivery Service Rates, Schedule E-2, page 10 of 371. Today, it is $26.91 for heating customers. For North Shore, the residential customer charge was $8.50 in 2007 for both heating and non-heating customers. *See Docket No. 07-0241, North Shore Gas Co. – Proposed Increase in Delivery Service Rates*, Schedule E-2, page 8 of 261. Today it is set at $23.75 for heating customers. The bottom line is that Peoples Gas and North Shore customers pay the highest rates in the state – both in terms of the customer charge and *per* therm charges. PGL's and NS's extraordinary request to seek 43% and 24% increases in the Residential Heating customer charge, respectively, threatens to exacerbate that reality.

While changes in rate design are intended to be revenue-neutral in impact, the practical reality is something different. In both the current and past rate cases, OAG expert Scott Rubin has repeatedly demonstrated in testimony that high customer charges mean the Companies' lowest users bear the brunt of rate increases, and subsidize the highest energy users. He has also demonstrated that the Companies' claims that all costs are fixed are belied by their own cost studies, which identify significant operational costs as tied to demand of natural gas. In addition, steadily increasing customer charges diminish the incentives to engage in conservation and energy efficiency because a smaller portion of the bill is subject to variable usage charges and customer efforts to reduce usage. AG/ELPC Ex. 3.0 at 15, 20-21.

As discussed further below, the Commission should reject the Companies' unsupported claim that customer charges must be raised to ensure cost recovery.

City-CUB's Position

The Companies' proposed rate design would require low-use/low-demand customers to subsidize high-use/high-demand customers. AG/ELPC Ex. 9.0 at 6. In fact, despite the proposed revenue requirement increase in this case, under the Companies' proposed rate design, some high use customers would see a decrease in their total distribution bill. AG/ELPC Ex. 3.0 at 15. PGL-NS claim that, under their proposed rate design, approximately 65-70% of an "average" residential heating customer's annual bill would be derived from variable charges. PGL-NS Ex. 43.0 at 6. However, the "average" low-use customer uses far less gas than the Companies' average customer, and low-use customers' resulting bills are much smaller. For those low-use customers, the amount of revenue derived from variable charges is far lower than for the class average customer, and the percentage of their bills attributable to fixed monthly charges is much greater.

In this delivery services rate proceeding, the Commission has jurisdiction to set – and should consider – only the portions of the customers' bills related to delivery services. Instead, the Companies' witness relies on comparisons and commentary respecting customers' total bills, which include commodity charges. This inappropriate comparison thus inflates the calculated amount of charges that vary for any given consumer, and deflates the calculated percentage of charges imposed through fixed monthly charges, especially for low-use/low-demand customers. Thus, (a) the actual relationship between proposed charges and cost-causing factors and (b) the impact of the proposed delivery service charges on customers are each distorted. The Companies' emphasis on total bills is an easily-perceived attempt at misdirection. The Commission should focus its review of customer bills on the portion of those assembled charges that is under the Commission's jurisdiction.

Within the residential service class, each customer in that class pays exactly the same fixed charge for demand-related costs under the Companies' proposed design. AG/ELPC Ex. 9.0 at 2. For the residential heating class, the Companies' ECOSS allocates demand costs only at the class level. Within the class, the Companies propose to spread demand costs uniformly across all customers, regardless of each customer's actual demand. Staff Ex. 9.0 at 4. The result is that low-use customers subsidize high-use customers in that class.

Even if one ignores the legislative policy of keeping gas utility service accessible, (220 ILCS 5/1-102(d)(viii)), the Companies' ECOSS justifies collecting a maximum of 63% of the total cost of service through the customer charge. AG/ELPC Ex. 3.0 at 15-16. However, to reach that 63% figure, one must accept the Companies' fiction that their demand costs are "fixed." But the Companies' ECOSS and the demand charges the Companies impose in other rate classes confirm that demand charges are not fixed. PGL Ex. 14.0 at 8; PGL Ex. 15.0 at 9, 10, 16, 19. Despite this limitation from their own study, which accepts their peculiar definition of "fixed" costs, the Companies propose to collect 75% or 90% of their revenues through fixed charges. PGL Ex. 15.0 at 12; 15. The Companies claim that this rate treatment of "fixed" costs -- which are inconsistently identified in their cost-causation based ECOSS -- does not produce the adverse effects detailed by other witnesses in this case. However, the Companies' claims are not validated by the record evidence or by common sense.

<u>SFV Rates Abandon Cost Causation And Give Inaccurate Price Signals</u>

The collective peak demands and energy needs of customers cause gas distribution facilities to be installed. Utility witnesses testify to the fact that a primary consideration in system design is to meet design day demand that may vary from year-to-year. In addition, Staff confirms that "[d]emand related costs service the peak demand of the system."

Accordingly, PGL-NS admit that there are good reasons for allocating the cost of distribution mains based on demand and usage. *Id.* at 3. As AG/ELPC witness Mr. Rubin observed, "[i]t makes no sense to say that the cost of serving residential customers is based, in part, on demand and energy usage; but then to design rates that ignore demand and energy usage." AG/ELPC Ex. 9.0 at 3.

A traditional rate design is more consistent with this cost causation relationship, as it is correctly defined by and recognized in the Companies' cost of service study. The Companies' proposed SFV rate design diverges from cost-causation, substituting its "fixed" cost designation for cost causation as the determinative allocator. Ms. Egelhoff claimed that the costs to install and maintain service needed to meet the demands of residential customers are likely to be the same by customer. This testimony is based on the belief that "demand-related costs do not vary by … the amount of demand [of] individual customers" whose collective demand is the cause of the Companies' demand costs. However, for most customers within a class, demands bear a pretty close relationship to annual usage. AG/ELPC Ex. 9.0 at 3, 7. The Companies' recommended rate design is aptly captured in AG/ELPC witness Mr. Rubin's restatement of the Companies' methodology: "well, we can't have precise demand metering, so let's just assume that every customer's demand is exactly the same." *Id.* at 7.

The Companies recover demand-related costs through demand-based charges in classes where customers have demand meters. The absence of demand meters in the Residential classes does not change the nature of those costs or why those costs are incurred, simply how they can be measured. Staff offers the illustrative example of a customer with a 4,000 square foot home paying the same amount for distribution mains as a customer with a 1,000 square foot home, even though the 4,000 square foot home customer "would use a larger share of distribution main capacity for its gas requirements." Staff Ex. 9.0 at 5. Honoring cost causation would require that the Companies' rates recognize that difference in what is used to provide service to those customers. As Staff witness Mr. Johnson observes, the Companies' proposal for a modified SFV rate design raises consistency issues. Under an SFV design, ECOSS-identified demand related costs, such as the cost of distribution mains, are labeled "fixed" and recovered through a uniform customer charge for all customers in the class.

The Commission has recognized the existence and effect of intra-class subsidies in the Companies' existing rate designs. Docket Nos. 12-0511/12-0512 (Consol.), Order at 218. The Commission's response was to approve a separation of non-heating customers from the rest of the residential class, as a means of recognizing the type of usage and demand cost differences the Companies' SFV proposal would ignore. *Id.* at 6-7. Ms. Egelhoff admits that the "fixed" costs that the Companies refer to are driven by customer demand and "can increase or decrease." PGL Ex. 8.0 REV. at 5; PGL-NS Ex. 29.0 at 7. If the costs of distribution facilities are collected based on customers' energy consumption or demand, then customers who consume more would pay most of any increase in demand costs, consistent with the correlation between usage and demand. Staff Ex. 9.0 at 4, 7.

Under a rate design that respects cost causation, demand-related costs should be collected (as causation suggests) through a demand charge, or through an energy charge if demand metering is unavailable. *Id.* at 5.

In any case, there is no revenue stability justification for the Companies' proposed rate design. The SFV design is proposed despite the existence of Rider VBA, which acts as a decoupling mechanism for S.C. Nos. 1 and 2 and reduces the Companies' financial risk of under-recovery of revenues. PGL-NS Ex. 29.0 at 5; Staff Ex. 4.0 at 19. The ICC has also reported that, because of Rider VBA, "the Commission can provide a mechanism for revenue stability that lowers the monthly customer charges and increases the volumetric charges. Such a change can decrease energy use by providing a greater price signal" to customers. *Id.* at 20 (quoting *Report to the Illinois General Assembly Concerning Coordination Between Gas and Electric Utility Energy Efficiency Programs and Spending Limits for Gas Utility Energy Efficiency Programs* at 23 (Aug. 30, 2013)).

In addition to Rider VBA, PGL has also implemented Rider QIP, which allows PGL to recover a return of and on the Company's investment in qualifying plant. The Companies also enjoy recovery of storage costs through Rider SSC. Further, PGL is essentially guaranteed a designated level of revenues for uncollectible accounts through Rider UEA.

SFV pricing, which the Companies advocate, fails to send customers an accurate signal about the costs associated with serving peak demands for natural gas. AG/ELPC Ex. 9.0 at 2. Acknowledging that fact, PGL-NS witness Ms. Egelhoff, referring to her proposed rate design, testified "I don't expect [customers] to change their behavior based on that message." Tr. at 138 (Sept. 23, 2014).

However, for that signaling effect, Ms. Egelhoff relies on charges that comprise a fraction of the total bill of an average PGL customer, and even less of a low-use/low-demand customer's bill. PGL-NS Ex. 29.0 at 9-10 (calculating that the cost of gas constitutes approximately 40% for Peoples Gas average residential heating customer's annual bill). In her testimony, Ms. Egelhoff identified the storage service charge, Natural Gas Savings Program, environmental charge, Uncollectible Expense Adjustment – Gas Cost adjustment, Volume Balancing adjustment, Qualified Infrastructure Plan charge, and taxes as variable components of a customer's bill. PGL-NS Ex. 43.0 at 6. However, Ms. Egelhoff admits that these charges comprise less than half the total bill of even the average Peoples Gas customer, l*et al*one a customer with lower usage than average.

By failing to send proper price signals, the Companies' proposed rate design denies consumers who conserve the benefit of their actions, and punishes customers who are frugal. The proposed SFV charges are indifferent to efficiencies in usage and demand. In contrast, the Commission has recognized that lower monthly customer charges and higher volumetric charges can advance energy use conservation and efficiency policy objectives by providing a greater price signal. Staff Ex. 9.0 at 8-9.

<u>The Companies' Proposed Rate Design Undermines Legislative And Commission Policies Supporting Energy Conservation And Efficiency</u>

The Companies also offer the false hope of encouraging conservation through their proposed rate design. Ms. Egelhoff claimed that customers' incentives to conserve are provided through required energy efficiency programming and that incorporating conservation into rate design is improper because it is "contrary to cost causation principles." PGL-NS Ex. 43.0 at 7. However, the Companies' proposal violates cost causation principles by failing to "properly recognize that customers with different demands impose differing costs on the system." Staff Ex. 9.0 at 5. The assumption behind Staff's and AG/ELPC's proposed rate design is more reasonable than the Companies' implied assumption that all customers within a class cause the utility to incur the same amount of demand costs. *Id.* at 7.

Ms. Egelhoff's claim further ignores the General Assembly's explicit directive to encourage energy efficiency. Section 8-104 of the PUA makes clear the General Assembly's interest in reducing the amount of natural gas delivered to utility customers and reducing the cost of utility bills that customers pay. The Companies' proposed rate design undermines the statutory programs by reducing the amount of a customer's bill that the customer has control over. The Commission has already recognized that reducing the fixed charges of customers can reduce overall natural gas usage, as envisioned by the General Assembly in creating the 8-104 energy efficiency programs.

(Report to the Illinois General Assembly Concerning Coordination Between Gas and Electric Utility Energy Efficiency Programs and Spending Limits for Gas Utility Energy Efficiency Programs at 24 (Aug. 30, 2013)).

Despite the proposed reduction in customers' ability to control their bills through favored conservation and efficiency actions, the Companies claim that SFV rate design provides a benefit in reducing the volatility of customers' bills. That is, customers would pay a fixed monthly charge that is unaffected by variations in weather or other conditions. In addition to ignoring the inflated charges incurred during the summer period, the Companies never establish why reducing customer bill volatility should be the objective of good rate design. Moreover, if some customers do value bill stability, they can voluntarily enter into a budget billing plan that achieves this end. Compelling all customers to accept (without choice) stable – but high – bills that include subsidies for other users is not a defensible Commission policy.

For these reasons, CUB and the City recommend that the Commission adopt the rate design proposal of AG-ELPC, as the most equitable, fair, and appropriate based on the facts in this record.

Peoples Fails to Justify Charging $38.50 *per* Month for the Fixed Charge

Peoples Gas proposes increasing its fixed customer charge for residential heating customers from the current $26.91 *per* month to $38.50 *per* month – a 43% increase. To state the obvious, this means that Peoples customers would pay $38.50 *per* month before using a therm of gas. Moreover, according to AG/ELPC Witness Rubin's calculations, "annual bill impacts would range from bill reductions (for a few thousand very high-use customers) to increases in excess of 30% (for the more than 30,000 customers using less than 250 therms *per* year)." Given this impact on customers, the Commission should set the bar very high in terms of what Peoples must show to justify this revenue shift.

Peoples Gas states its objective is a desire to "better align revenues with underlying costs." PGL Ex. 15.0 at 9. As the major reason for doing this Witness Egelhoff asserts, "Recovering fixed costs through a variable distribution charge sends an incorrect price signal to customers that the more gas they use the more it costs the Companies to provide them delivery services." Peoples Ex. 29.0 at 3. In essence, Ms. Egelhoff argues that Peoples wants to correct customers notion that the more gas they use, the higher the cost of service.

Peoples argues that putting "fixed cost" in a variable charge sends the wrong price signals. Its rate design moves more of the fixed cost recovery from variable charges into fixed charges. ELPC submits that this answer is nonsensical.

One thing clear from the record is that this is not about helping customers or changing customer behavior. Normally, one would expect the company to argue that if it sends customers the right message (price signal) then we can expect customers to change their behavior.

Peoples argues that fixed costs should all be recovered through fixed charges. Both AG/ELPC Witness Rubin and Staff Witness Johnson dispute the assertion that usage charges are fixed:

> A gas distribution system is designed to serve the anticipated peak demands and energy requirements of all customers. Very little if any of that investment is actually "caused" by a single customer. When we talk about the principle of cost causation, we're actually talking about a fair way to allocate shared costs among customer classes and customers.

AG/ELPC Ex. 9.0 at 2. Rubin further notes that there is a question of fairness between customer classes, because if residential customers increase their usage more of the cost of a gas main should then be transferred to that customer class. *Id.* at 3-5. Thus, you want to send the correct price signal to members of that class.

Staff witness Johnson in his testimony emphasized that long term, fixed costs increase when customers use more gas. Holding down usage, ultimately translates to a less costly system. In essence, Peoples defines fixed costs in a very narrow and inaccurate way that the facts do not support.

<u>The Commission Recently Issued a Report to the General Assembly Concluding that Rate Design Should Encourage Efficiency</u>

The issue of rate design and the Companies desire to shift revenue into fixed monthly charges is not unique to Peoples and has been a significant issue in a number of states in recent years, including Illinois. The ICC recognized the importance of this issue and addressed it directly in the ICC Report to the General Assembly Concerning Coordination Between Gas and Electric Utility Programs and Spending Limits for Gas Energy Efficiency Programs, August 30, 2013 ("Energy Efficiency Report"). The Commission reaches a conclusion that the gas companies can reach their savings targets by shifting revenue from the fixed customer charge to the volumetric charge. Report at 22. The Commission conclusion lies in direct contradiction to Peoples' proposal in this proceeding.

The Report does an excellent job of analyzing the issue Peoples poses in this proceeding. In terms of the proper rate design moving forward, the Commission argues that revenue should be shifted back from fixed charges to volumetric charges going forward:

> The importance of these findings is that increasing the volumetric distribution charge by even 10% (the distribution charge is approximately 40%-50% of the bill) could lead to a 0.4%-0.5% short term reduction and 0.88%-1.1% long-term reduction in gas use over what it would be with the lower volumetric price19. Because altering the volumetric charge does not affect the average cost of delivery service to retail customers (it does affect the costs to individual customers but on average a customer pays the same amount), these additional savings can be achieved without increasing the budget limitations. If prices and weather are similar to what was experienced in 2009, one should expect that increasing the volumetric distribution charge by 10% would achieve a

> usage reduction that is about half of the May 31, 2015 goal of 0.8%.

Id. at 24. Hence, the Report's conclusion directly contradicts Peoples request.

The legislature's general directive is that public utilities must furnish service that protects the public, "and as shall be in all respects adequate, efficient, just, and reasonable." 220 ILCS 5/8-10.1. Read in its totality, the Public Utilities Act stresses the value of efficiency, and Ms. Egelhoff's reading that the Commission should not consider the rate design effect on efficiency contradicts the letter and spirit of the law. The legislature's point is that it has set efficiency targets that the utility should meet for the protection of Illinois customers; it did not set the targets in a vacuum and the Commission would not have taken the position that it should use rate design to affect efficiency in the Report if it believed this contradicts the Public utilities Act.

Peoples Demonstrates No Revenue Issues and Decoupling Guarantees its Revenues

AG/ELPC witness Rubin asserts that the main reason that a utility would need to collect more revenue through the customer charge stems from uncertainty over cost recovery that generally stems from a decline in sales. AG/ELPC Ex. 3.0 at 17. In fact the record reflects that few if any Companies have ever had greater revenue certainty, or face less risk. Rider VBA adjusts PGL's revenue collections for any changes in consumption as compared to the forecasted amount." Id at 18. Rider SSC assures Peoples it will collect all of its storage related costs, and Rider UEA guarantees Peoples will collect all of its uncollectibles. *Id.*

In addition to the revenue adjustments above, Rider QIP, approved in Docket No. 13-0554, allows Peoples to collect an immediate return on its infrastructure investments through Rider QIP. *Id.* Combined with the revenue adjustment above, Peoples has more than enough certainty without increasing its fixed charge.

Peoples Fixed Charges Currently Exceed Reasonable Levels

Peoples has already received a number of increases to its fixed customer charge, as this charge has increased from $9.00 *per* month in 2007 to the current $26.91 *per* month in 2014. The following table sets out the recent history:

	North Shore current	**North Shore proposed**	**Peoples Gas current**	**Peoples Gas proposed**
2007	$8.50	$16.00	$9.00	$19.00
2009	$13.50	$19.90	$15.50	$23.30
2011	$17.80	$24.75	$19.50	$28.21
2012	$22.00	$27.70	$22.25	$32.83
2014	$23.75	$29.55	$26.91	$38.50
% increase total	179% since 2007		199% since 2007	

Simple math indicates the Commission has allowed Peoples to increase its customer charge by 179% in only seven years, which raises questions about the tone of Peoples' testimony in terms of the need to correct a dire problem. In fact, the record indicates the opposite situation; the Commission has shifted too much revenue to the fixed monthly charge and it needs to reverse the trend.

Under present rates, PGL's customer charges collect approximately 62% of non-storage revenues from heating customers and 81% from non-heating customers. The proposed changes would raise those percentages to approximately 75% heating and 90% non-heating. *Id.* at 15. Instead, ELPC recommends that the ICC adjust Peoples' fixed charges consistent with the recommendations made by AG/ELPC Witness Rubin.

The exact amount of the customer charge depends on whether the Commission grants Peoples a rate increase, and if so what amount it approves. Mr. Rubin proposes a rate design that collects approximately 52% of non-storage revenue from HTG customers through customer charges and 73% from NH customers. *Id.* at 24. Based on this recommendation, even if the Commission grants Peoples its full proposed revenue increase, the HTG customer charge would remain at $26.91. If the Commission determines that Peoples has not met its burden regarding the rate increase, "[T]he rates should be scaled back proportionately so that the HTG customer charge would be designed to collect between 50% and 52% of non-storage revenues and the NH customer charge would be designed to collect approximately 73%-75% of non-storage revenues." *Id.* at 24-25. This recommendation is in line with the finding in the Commission's Report that a 10% shift of revenue from fixed charges to variable would send the correct price signals on efficiency.

Peoples Proposed Shift of Revenue to Fixed Costs is not Just and Reasonable

As set forth above, Peoples analysis regarding fixed costs fails to correctly analyze the true nature of Peoples' sunk costs in the delivery system. More than that though, Peoples' proposal violates fundamental fairness principles. As Mr. Rubin asserts, "Giving PGL's customers more control over their natural gas bills by reducing the customer charge gives customers an important incentive to reduce their energy usage." AG/ELPC Ex. 3.0 at 21. Given the legislature's desire to promote energy efficiency, the Commission should ensure that Peoples' rate design does not reduce the value of efficiency. The current customer charge of $26 *per* month already reduces customer benefits from efficiency and an increase to $38.50 speaks for itself.

The Illinois Commerce Commission recently ordered ComEd to reduce its fixed charges and increase its variable rates to better protect low-usage customers The Commission should take similar action in this proceeding as well.

Commission Analysis and Conclusion

The principal rate design issue in this case is the type of charge -- fixed or volumetric -- through which the Companies should recover non-storage demand-classified distribution costs. The Companies contend that virtually all of their costs are fixed costs which should be recovered through fixed charges---primarily the customer charge. The Companies assert that because in their analysis these costs do not vary with gas use, rate design should gradually evolve to reflect this.

The Companies argue that all demand-classified costs (*e.g.*, storage, land, structures and improvements, mains, compressor station equipment and measuring and regulating equipment) are fixed costs. The Companies contend that the costs of this type of investment do not vary with customer usage or even if the customer's demand day requirements change. In other words they seek approval for a rate design that increases the percentage of fixed costs and reduces the percentage of variable costs.

The Companies contend that SFV is merely a term describing a rate design under which all fixed costs are recovered in fixed charges. The Companies' proposed rate designs in its recent cases have moved progressively closer to an SFV rate design although they insist that they are not proposing SFV rate designs.

The Companies' revenue recovery is virtually guaranteed through the existence of Rider VBA, which acts as a decoupling mechanism for S.C. Nos. 1 and 2 and reduces the Companies' financial risk of under-recovery of revenues. In addition to Rider VBA, PGL has implemented Rider QIP, which allows PGL to recover a return of and on the Company's investment in qualifying plant, further mitigating any concern about the Companies' revenue stability. The Companies also enjoy recovery of storage costs through Rider SSC. Further, PGL is essentially guaranteed a designated level of revenues for uncollectible accounts through Rider UEA, which provides monthly adjustments to customers' bills for over or under collection of PGL's actual uncollectible expenses.

The record demonstrates that the Companies' ECOS studies take functional costs and allocate them by cost causation into commodity related, demand related, and customer related. Each class is then assigned commodity, demand, and customer related costs. Residential customers do not have demand meters. Demand related costs for classes other than residential customers are allocated based on demand, rather than the assumption that each customer contributes equally to demand. Staff and the Interveners argue the Companies' rate design would create inconsistency between how costs are caused and normally allocated and how revenues are collected for the residential classes.

The principal debate is about how the small residential service revenue requirement and the general service revenue requirement should be allocated in the absence of demand meters. The Companies' rate design, in this and prior cases, generally seeks to recover the demand costs in both fixed and variable charges, with gradual movement towards placing recovery of all of these costs as fixed charges. The Companies strongly insist that it is false that day-to-day usage causes any change to these costs. Therefore for a rate class that does not include a demand charge, a fixed charge, like the customer charge, is a better cost causal rate design than a variable charge, like the distribution charge.

The Companies' proposed SFV-based rate design shifts a greater percentage of cost recovery from a *per* therm basis to a *per* customer basis. Assigning demand related costs to the customer charge assumes each customer in the class contributes equally to the class demand. The Companies assert that it is peak demand that determines system cost and that that cost is essentially the same no matter how much or how little gas an individual customer uses. To the contrary, Staff and the Intervenors assert that there is no evidence in the record to support this assumption. They argue that usage is a reasonable proxy for demand and that demand type charges should be allocated on that basis.

Staff contends the relevant question here is not the cost of the infrastructure built to meet demand but rather who should pay for it. If demand costs are recovered through the customer charge, all customers are assumed to cost the same for the Companies to serve them. If demand costs are recovered through the distribution charge, the recovery method assumes the costs are not the same for all customers to serve them and that customers with higher usage will have higher peak demands and be more costly to serve than small use customers. As Staff notes, while this may not be true in each and every case, it is more reasonable than the Companies' proposed rate design's implied assumption that all customers within a class cause the utility to incur the same amount of demand costs.

The Companies' rationale for its design is that it allocates costs to cost causers. Staff and the Interveners argue that this is incorrect. Moreover, the net result of the Companies proposal is to reduce the effect of increased usage on the customers' bill. The Companies' rate design encourages increased consumption through lower *per* therm distribution charges. Thus, the price signal for ratepayers to conserve is weakened. Allocating these costs *per* customer, also penalizes low usage customers whose bills are higher on a *per* therm basis than high use customers.

Under the Staff and Intervenor proposals, when a customer uses more gas -- on a peak or other day -- he pays more towards demand costs, and when he uses less gas, he pays less towards demand costs.

This Commission has recognized that SFV rate designs are inconsistent with energy conservation. *See* Energy Efficiency Report. In Docket No. 13-0387, our Order adopted adjustments to ComEd's rate design in Docket No. 13-0387, which moved away from SFV-based rate design through lower fixed cost recovery. Similarly, in Docket No. 13-0476 this Commission rejected a requested increase in fixed cost recovery through a modified SFV rate design. Docket No. 13-0476, Order on Rehearing at 42 (September 30, 2014).

In Docket Nos. 12-0511 and 12-0512, this Commission ordered PGL and NS to establish separate rates and customer classes for residential heating and non-heating customers resulting in a substantial reduction in the bills for non-heating customers, due to the significantly lower demand-related costs of serving those customers.

In this case, Peoples Gas seeks to increase the heating gas customer charge from \$26.91 to \$38.50, a 43% increase. North Shore seeks to increase that charge from current \$23.75 to \$29.55, an increase of 24%.

Under present rates, PGL's customer charges collect approximately 62% of non-storage revenues from heating customers and 81% from non-heating customers. The proposed changes would raise those percentages to approximately 75% heating and 90% non-heating. *Id.* at 15.

The exact amount of the customer charge depends on the amount of the rate increase. Mr. Rubin proposes a rate design that collects approximately 52% of non-storage revenue from HTG customers through customer charges and 73% from NH customers. *Id.* at 24. Based on this recommendation, even if the Commission grants Peoples its full proposed revenue increase, the HTG customer charge would remain at $26.91.

It is patent that high customer charges mean the Companies' lowest users bear the brunt of rate increases, and subsidize the highest energy users. Steadily increasing customer charges diminish the incentives to engage in conservation and energy efficiency because a smaller portion of the bill is subject to variable usage charges and customer efforts to reduce usage.

The Commission rejects the Companies' claim that customer charges must be raised to ensure cost recovery. The Commission finds that SFV based rates that assume that non-storage demand related distribution costs should be allocated on a *per* customer basis are inconsistent with the public policies of attributing costs to cost causers, encouraging energy efficiency and eliminating inequitable cross-subsidization of high users by low users of natural gas.

Although Staff and Intervenors agree on the shift away from SFV based rates, they disagree on the percentage of fixed costs. Consistent with the more conservative rate design proposed by Staff, the Commission directs that Staff's proposed S.C. No. 1 Residential Non-Heating, S.C. No. 1 Residential Heating, and S.C. No. 2 General Service rate designs, as discussed in Sections IX.C.2.a, IX.C.2.b., and IX.C.2.c., respectively, be approved. Any increase in non-storage demand-classified distribution costs beyond the revenue provided by Staff's proposed customer charges should be collected through volumetric charges. The Commission finds that the Companies' risk of not recovering their authorized revenue requirement are minimal in light of the guaranteed revenue recovery that the Companies enjoy through decoupling, uncollectibles and infrastructure riders.

C. Service Classification Rate Design

1. Uncontested Issues

a. Service Classification No. 8, Compressed Natural Gas Service (PGL)

Companies' Position

Peoples Gas proposed to set S.C. No. 8, Compressed Natural Gas Service, at cost. PGL Ex. 15.0 REV. at 10. North Shore does not have a comparable service classification.

Staff's Position

North Shore does not currently have a Compressed Natural Gas Service class. Peoples Gas is proposing to set the S.C. No. 8 Compressed Natural Gas Service class at cost. PGL Ex. 15.0 at 19. Seventy-five percent of total customer costs are recovered through the customer charge under the Company's proposal compared to the current

50%. The Company is taking a gradual approach for bill impact reasons. Staff Ex. 4.0, 62. The revenues in total from all charges will recover the full cost to serve the customers. The S.C. No. 8 class is available to any customer for gas to be used as compressed natural gas to fuel a vehicle. *Id.*

Staff has no objection to Peoples Gas' rate design proposal for the S.C. No. 8 rate class. Staff opined that it is important that the S.C. No. 8 rates reflect the full class cost of service so customers can make informed decisions concerning their use of natural gas in vehicles and their possible purchases of natural gas vehicles. Id. at 63. No other party provided written testimony addressing the S.C. No. 8 class.

<u>Commission Analysis and Conclusion</u>

The Commission finds that Peoples Gas' rate design for its compressed natural gas service classification is appropriate and reasonable. It is proper to set this service classification at cost. The proposal is uncontested. The Commission approves Peoples Gas' proposed S.C. No. 8 rate design.

b. S.C. No. 5 Contract Service for Electric Generation and S. C. No. 7 Contract Service to Prevent Bypass

North Shore and Peoples Gas proposed no changes to S.C. Nos. 5 and 7, and they exclude these classes from consideration because the revenues from these customers are based on negotiated rates rather than the ECOSSs. NS Ex. 15.0 at 8 9, 19; PGL Ex. 15.0 REV. at 8-9, 19.

The Commission finds that the Companies' proposals not to revise these service classifications are appropriate and reasonable. The proposals are uncontested. The Commission approves no changes to S.C. Nos. 5 and 7.

2. Contested Issues- North Shore and People Gas

a. Service Classification No. 1, Small Residential Service, Non-Heating

<u>Companies' Position</u>

The Companies stated that, consistent with the rate design objectives and principles applicable to fixed cost recovery, they each proposed to continue to set S.C. No. 1 NH at cost. NS Ex. 15.0 at 10; PGL Ex. 15.0 REV. at 10. North Shore and Peoples Gas each proposed to recover 90% of non-storage related fixed costs through the customer charge with all remaining non-storage costs being recovered through a flat distribution charge. Each would continue to recover storage-related costs under Rider SSC. NS Ex. 15.0 at 11; PGL Ex. 15.0 REV. at 11. The Companies contend that their proposals are consistent with the Commission policy for gas Companies of gradually increasing fixed cost recovery in fixed charges. To retreat from this gradual movement, as AG/ELPC and potentially Staff proposed, exacerbates the extent to which a customer's bill does not reflect the costs it causes the Companies to incur. The Companies also stated that the IIEC's flawed across-the-board increase should be rejected.

Staff's Position

The Commission should have the Companies begin the process of moving away from SFV-based rate design. By assuring that the S.C. 1 NH class' customer charge reflects ECOS study-based customer costs only, the Commission can start the movement away from SFV-based rates for North Shore and Peoples Gas and ensure that customers are instead paying for the ECOS study-based costs they cause.

The Companies propose fixed customer charges for North Shore and Peoples Gas that recover 90% of non-storage related fixed costs through the customer charge. The Companies also propose a flat distribution charge *per* therm for sales and transportation customers. NS Ex. 15.0 at 11; PGL Ex. 15.0REV at 11.

Staff witness Johnson found that the Companies' total customer charge revenues derived from their proposed customer charges reflect approximately 97% of the total ECOS study-based customer costs for the Companies. Therefore, under the Companies' proposal, customers in the S.C. No. 1 NH class would pay for ECOS study-based customer costs in the customer charge and ECOS study-based demand costs in the single block distribution charge. This methodology is consistent with the rate design the Commission approved for ComEd in Docket No. 13-0387 and favored in Ameren Docket No. 13-0476. Therefore, Staff witness Johnson has no objection to the proposed customer charge and flat distribution charge recommended by the Companies. They both recover their individual ECOS study-based costs. Staff Ex. 4.0, 26-27, 45.

However, Mr. Johnson's agreement with the Companies' proposed customer charge and flat distribution charge is not an acceptance of the Companies' theory for their proposed SFV-based rate design with 90% fixed cost recovery. If North Shore's total customer charge revenues derived from the proposed customer charge ($15.80) are greater than the customer costs found on the final Commission approved ECOS study in this proceeding, then the final customer charge should be lowered to recover ECOS study-based customer costs only. Likewise if Peoples Gas' total customer charge revenues derived from the proposed customer charge ($16.70) are greater than the customer costs found on the final Commission approved ECOS study in this proceeding, then the final customer charge should be lowered to recover ECOS study customer costs only. Any remaining revenues for either Company would be collected through the flat distribution charge. *Id.* at 27. Staff's proposed rates, which are based upon the Companies' proposed direct testimony revenue requirement (Staff Ex. 4.0 at 24.), can be found at Staff Ex. 4.0, Schedule 4.01N and Schedule 4.01P.

In rebuttal testimony, the Companies opposed Staff's conditional approval that the Companies' total customer charge revenues derived under the Companies' proposed rate designs and the final Commission approved ECOS studies should not result in more than customer cost recovery through the customer charge. Companies witness Egelhoff stated that all of the Companies' costs recovered through base rates are fixed. NS-PGL Ex. 29.0 REV at 15.

Staff witness Johnson responded that the Companies' position reflects the overall disagreement on whether the customer charge should recover only customer costs (traditional rate design) or include costs related to customer demands (100% SFV or SFV-based). As Staff discussed in direct testimony, the Commission is moving away from an SFV-based rate design and back to a more traditional rate design approach, *i.e.*, all demand-related costs are recovered through the variable charge and all customer-related costs are recovered through fixed charges. The Commission's recent Orders make it clear that SFV-based rate designs should be re-examined and rates should reflect traditional rate design principles, which more closely align customers' bills with the ECOS study. Docket No. 13-0387, Order at 75; Docket No. 13-0476, Order at 101 (March 19, 2014); Staff Ex. 9.0 at 12.

Staff witness Johnson opined that a traditional rate design approach more closely aligns rates with cost causation principles. As discussed under the Fixed Cost Recovery section above, if demand costs are recovered through the customer charge, all customers are assumed to cost the same to serve. If demand costs are recovered through the distribution charge, the cost to serve each customer is based upon usage. While both cost recovery methods are not exact, recovering demand costs through the distribution charge takes into consideration that customers do place different costs on the system. *Id.*

AG's Position

Peoples Gas and North Shore propose to substantially increase the customer charges for both heating ("HTG") and non-heating ("NH") customers and to reduce the *per*-therm distribution charges for both classes. In particular, Peoples Gas proposes the rate increases for Non-heating Residential customers as shown in the following tables:

PGL Rate	**Present**	**PGL Proposed**	**% Increase**
NH customer charge	$13.60	$16.70	+ 22.8%
NH volumetric charge (including VBA)	$0.43626	$0.24087	- 44.8%

North Shore Rate	**Present**	**PGL Proposed**	**% Increase**
NH customer charge	$13.65	$15.80	+ 15.8%
NH volumetric charge (including VBA)	$0.27292	$0.13748	- 49.6%

AG/ELPC Ex. 3.0 at 14, 25. Under present rates, PGL's Non-Heating customer charges collect approximately 81% of non-storage revenues. For North Shore, the Company's Non-Heating customer charges under present rates recover 80% (NH) of non-storage revenues. The proposed rate changes would increase those percentages to approximately 90% for both Companies.

AG/ELPC rate design witness Scott Rubin analyzed the Companies rate design and found it lacking in many regards. First, the Companies own cost studies reveal that there are significant demand –related costs, that is, costs that are impacted by customer demand for natural gas. Such costs should never be recovered through fixed customer charges. AG/ELPC Ex. 3.0 at 15. Mr. Rubin's uncontested analysis for PGL's NH customer class shows that approximately 7% of the cost of serving the class is demand-related. AG/ELPC Ex. 3.0 at 16. This means that 93% of the NH cost of service is customer related. Again, this is the theoretical maximum amount that should be collected through the NH customer charge. For North Shore, approximately 7% of the cost of serving the Non-Heating Residential class is demand-related. This means that 93% of the NG cost of service should be collected through the Non-Heating customer charge. AG/ELPC Ex. 3.0 at 27.

Using PGL's actual billing data for the test year, Mr. Rubin determined that the range of impacts is very diverse – and unwarranted – for the Companies' NH customers. As shown on AG/ELPC Ex. 3.3, the impacts range from annual increases approaching 20% (customers using 25 therms or less *per* year) to sizeable bill reductions for those customers using more than 200 therms *per* year. AG/ELPC Ex. 3.0 at 22. Once again, validating the classification of higher-use NH customers might eliminate some of these bill reductions, but there will remain customers at the high end of the class whose annual bills would be lower under PGL's rate design than they are now, even though PGL is proposing nearly a 10% increase in revenues collected from the NH class.

For NS NH customers, the impacts range from annual increases approaching 15% (customers using 25 therms or less *per* year) to sizeable bill reductions for those customers using more than 200 therms *per* year. *Id.* at 28. Once again, validating the classification of higher-use NH customers might eliminate some of these bill reductions, but there will remain customers at the high end of the class whose annual bills would be lower under the NS rate design than they are now.

To remedy these cross-subsidization inequities between low and high users, Mr. Rubin recommended that PGL and NS should move toward collecting no more than 75% of their respective Non-Heating class revenues, from the customer charges. Under the Companies' proposed revenue requirements, Mr. Rubin's proposed rate design would collect approximately 73% of PGL Non-Heating (non-storage) revenues and 78% of North Shore Non-Heating revenues through the customer charges. This change will start the process of restoring the Companies' residential customer charges to more traditional levels. Further, Mr. Rubin's proposals will rationalize the rate design, consistent with the Companies' own cost studies, give customers more control over their bills (thereby ensuring consistency with the State's energy efficiency goals), and start to alleviate some of the impacts of the rate design on low-income customers that AG witness Colton discusses in his testimony. His proposed rates are:

Rate	**Present**	**AG/ELPC Proposed**	**% Increase**
PGL NH customer charge	$13.60	$13.60	0.0%
PGL NH volumetric charge (including VBA)	$0.43626	$0.64901	+ 48.8%
NS NH customer charge	$13.65	$13.65	0.0%
NS NH volumetric charge (including VBA)	$0.27292	$0.30634	+ 21.5%

AG/ELPC Ex. 3.0 at 24, 29. Again, assuming 100% recover of PGL's proposed revenue requirement, the AG/ELPC-proposed rate design would collect approximately 73% of PGL's Non-Heating non-storage revenues and 78% of North Shore Non-Heating non-storage revenues through the customer charges. *Id.* at 24, 30. If approved, this change would start the process of restoring PGL's residential customer charges to more traditional levels.

In the very likely possibility that the Commission determines that Peoples Gas should receive a lower rate increase than Peoples Gas requested, the rates shown in the above table should be scaled back proportionately so that the PGL Non-Heating customer charge would be designed to collect approximately 73% to 75% of non-storage revenues, and the NS Non-Heating customer charge would collect approximately 75% to 78% of non-storage revenues.

Coupled with the approval of the AG/ELPC proposed Residential Heating rate design discussed below, these rates will rationalize the Companies' overall Residential rate design, give customers more control over their bills (thereby ensuring consistency with the State's energy efficiency goals), and start to alleviate some of the impacts of the modified SFV rate design approved to date by the Commission has had on low-income customers that AG witness Colton discusses in his testimony. The policy reasons that support Mr. Rubin's proposed Non-Heating rate design related to the Company's lack of risk in revenue recovery are further discussed below in the Residential Heating section of the Brief below, and will not be repeated here.

AG/ELPC witness Rubin is proposing that PGL and NS move toward collecting no more than 50% of its heating revenues, and no more than 75% of its non-heating revenues from the customer charges. AG/ELPC Ex. 3.0 at 22, 29. Mr. Rubin states that under PGL's proposed revenue requirement, the 50% and 75% results can be approximated by keeping PGL's heating and non-heating customer charges at their existing amount. Thus, the increase would be collected solely through increases in the volumetric charges. *Id.* at 22.

For NS, Mr. Rubin states that under North Shore's proposed revenue requirement the effects on larger-use heating customers might be severe if the change were made in one step, so Mr. Rubin recommends the residential customer charges should remain at their existing amounts. *Id.* at 29.

Mr. Rubin's proposed Non-Heating Residential rate design, should be adopted by the Commission.

<u>Commission Analysis and Conclusion</u>

The Commission finds that the Companies' proposed increases in the customer charges pursuant to its SFV based rate design are inconsistent with public policy as discussed in Section IX, B 2 (Fixed Cost Recovery) of this order. The Commission finds that IIEC's proposal for an across the board increase in rates is not supported by the evidence. Staff's proposal to move away from SFV based rates is reasonable and supported by the record

The Commission accepts Staff's rate design proposal for this customer class, which reflects a more traditional rate design whereby customer charges recover embedded cost-of-service ("ECOS") study customer costs and distribution charges recover ECOS study demand costs. Therefore, customer's bills are more closely aligned with the ECOS study. The customer charges for the S.C. No. 1 Small Residential Service, Non-Heating class should be set to recover the final Commission approved ECOS studies' customer costs. The remaining, non-storage related demand costs, would be recovered through a flat distribution charge on a per therm basis.

b. Service Classification No. 1, Small Residential Service, Heating

Companies' Position

The Companies stated that, consistent with the rate design objectives and principles applicable to fixed cost recovery, they each proposed to continue to set S.C. No. 1 HTG at cost. NS Ex. 15.0 at 10; PGL Ex. 15.0 REV. at 10. North Shore proposed to recover 80% and Peoples Gas proposed to recovery 75% of non-storage related fixed costs through the customer charge with all remaining non-storage costs being recovered through a flat distribution charge. Each would continue to recover storage-related costs under Rider SSC. NS Ex. 15.0 at 12; PGL Ex. 15.0 REV. at 12. The Companies contend that their proposals are consistent with the Commission policy for gas companies of gradually increasing fixed cost recovery in fixed charges. To retreat from this gradual movement, as AG/ELPC and Staff proposed, exacerbates the extent to which a customer's bill does not reflect the costs it causes the Companies to incur, *i.e.*, customer usage would drive fixed cost recovery but usage does not drive the Companies' incurrence of those fixed costs.

Staff Position

Staff urges the Commission to accept Staff's proposal to set the S.C. No. 1 Heating classes' customer charges to recover ECOS study customer costs and set distribution charges to recover ECOS study demand costs.

North Shore is proposing to increase the recovery of fixed costs in its SFV-based rate design to recover 80% of non-storage related fixed costs through the customer charge, compared to the current 68% fixed cost recovery, with all remaining costs being recovered through a flat distribution charge. The monthly customer charge would increase from $23.75 to $29.55 and the distribution charge would decrease from 10.385 cents *per* therm to 7.133 cents *per* therm. This is applicable to both sales and transportation customers. NS Ex. 15.4. Peoples Gas is proposing to increase the recovery of fixed costs in its SFV-based rate design to recover 75% of non-storage related fixed costs through the customer charge, compared to the current 61% fixed cost recovery, with all remaining costs being recovered through a flat distribution charge. The monthly customer charge would increase from $26.91 to $38.50 and the distribution charge would decrease from 18.885 cents *per* therm to 14.919 cents *per* therm. This is applicable to both sales and transportation customers. PGL Ex. 15.4.

Staff witness Johnson's assessment of the Companies proposal found that North Shore's proposed customer charge would recover approximately $51,355,507 in total annual customer charge revenues while the ECOS study identifies only $43,452,183 in customer costs for the S.C. No.1 HTG class. He found Peoples Gas' proposed customer charge would recover approximately $303,291,027 in total annual customer charge revenues while the ECOS study identifies only $254,928,725 in customer costs for the S.C. No.1 HTG class. Staff Ex. 4.0 at 28. Mr. Johnson opined that these proposals are inconsistent with the Commission's recent orders, which adopt rate designs that move away from an SFV-based rate design and instead align customers' bills with the cost of service (*i.e.*, customer charges based upon ECOS study customer costs and distribution\demand charges based upon ECOS study demand costs). *Id.* at 29. Staff's proposed rate design which sets customer charges based upon ECOS study customer costs and distribution charges based upon ECOS study demand costs would consist of a $25 monthly customer charge and 11.544 cents *per* them distribution charge for North Shore and a $32.35 monthly customer charge and 22.063 cents *per* therm distribution charge for Peoples Gas. NS-PGL Ex. 29.0 REV at 17-18. Staff's proposed rates are based upon the Companies' proposed direct testimony revenue requirement. Staff Ex. 4.0 at 24.

Moreover, Staff found that because the Companies' proposed customer charges are based upon all ECOS study customer costs and part of the demand costs, the resulting lower distribution charge results in those customers that are incurring greater demands on the system to not paying their fair share. This occurs because under the Companies' proposal, demand costs are recovered through the customer charge, thereby shifting cost recovery from a *per* therm basis to a *per* customer basis. The lower-use heating customers in effect would subsidize the larger-use heating customers.

Finally, in order to reflect the proper price signal and encourage energy conservation, the distribution charge should reflect all demand related costs so that those customers who place greater demands on the system pay for those demands.

In the rebuttal stage of this proceeding the Companies stated that all of their costs recovered through base rates are fixed and that the cost of having infrastructure in place to handle that demand does not vary based on a customer's use. NS-PGL Ex. 29.0 REV at 17.

Recent Commission Orders indicate a movement away from SFV-based rate designs, especially for those Companies with cost recovery mechanisms in place (like the Companies' Rider VBA) that provide revenue stability. Staff's rate design proposal makes a similar movement while taking rate impacts into consideration. Staff Ex. 9.0 at 14.

AG/ELPC witness Rubin is proposing that PGL and NS move toward collecting no more than 50% of its heating revenues, and no more than 75% of its non-heating revenues from the customer charges. Mr. Rubin states that under PGL's proposed revenue requirement, the 50% and 75% results can be approximated by keeping PGL's heating and non-heating customer charges at their existing amount. Thus, the increase would be collected solely through increases in the volumetric charges. *Id.* at 22.

For NS, Mr. Rubin states that under North Shore's proposed revenue requirement the effects on larger-use heating customers might be severe if the change were made in one step, so Mr. Rubin recommends the residential customer charges should remain at their existing amounts. *Id.* at 29.

Staff witness Johnson stated that it is not clear how Mr. Rubin derived the percentages of 50% and 75% for heating and non-heating, respectively. Mr. Rubin states that PGL's ECOS study shows that 64% of heating costs are customer related and 93% of non-heating costs are customer related. *Id.* at 16. He also states that NS' ECOS study shows that 67% of heating costs are customer related and 93% of non-heating costs are customer related. *Id.* at 27. He emphasizes that these are the maximum amount of costs that should be collected through the customer charge because the percentages from the ECOS studies assume that it is proper to recover all distribution-related costs that are classified as customer-related through the customer charge. He argues that traditionally NS and PGL collected a portion of those customer-related distribution costs through a volumetric charge. *Id.* at 16, 26-27. Staff argues that Mr. Rubin has not provided any type of evidence to justify that the distribution-related costs that are classified as customer-related should just be classified as distribution-related. Staff Ex. 9.0 at 24.

Staff also stated that it is also not clear whether the 50% and 75% figures are based upon Mr. Rubin's assumption that the ECOS study distribution-related costs recovered through the customer charge should be recovered through the volumetric charge or are based upon some other reason. Therefore, Staff witness Johnson stated that he continues to recommend that the Commission accept Staff's rate design proposal as set forth in direct testimony. *Id.*

AG's Position

As noted by AG/ELPC witness Rubin, the Companies' proposed changes to residential heating rates, in particular, are inequitable and inconsistent with both the Companies' own cost studies and public policy goals related to conservation and energy efficiency. As noted in the Rate Design Overview section above, Peoples Gas and North Shore residential heating customer charges have risen by nearly 200% and 179%, respectively, since 2007, the year PGL/NS began filing a steady stream of rate cases under its new parent company, Integrys, and are the highest in the state by a long shot. Both PGL and NS want to increase the amount of revenue they receive from customers through non-variable charges. Peoples Gas is proposing to increase its Heating revenues recovered in this case by another 17.3%, but proposes an increase in the PGL customer charge of 43.1%.

Under present rates, PGL's residential Heating customer charges collect approximately 62% (HTG) of non-storage revenues. The proposed rate changes would increase those PGL percentages to approximately 75% (HTG). *Id.* at 15.

Similarly, North Shore seeks to increase its overall Heating revenues by 5.2%, but increase the NS customer charges by more than 24%. AG/ELPC Ex. 3.0 at 25. Under present rates North Shore collects approximately 68% of non-storage revenues through the customer charge. The proposed North Shore rate changes would increase this percentage to approximately 80% (HTG) for North Shore customers

The proposed changes are significant and would result in customer bill impacts being very different from the class average rate increase. Specifically, low-use customers would see much greater than average increases, while high-use customers would have increases much lower than average, and in some cases even decreases in their total distribution bill. AG/ELPC Ex. 3.0 at 15, 25. As Mr. Rubin explained, PGL's proposals are not consistent with either sound rate design principles or reasonable cost-of-service principles.

First, as Mr. Rubin noted, a significant portion of the cost of serving heating customers is demand-related costs. In classes that have demand meters, demand-related costs are collected from customers in proportion to each customer's actual demand. In classes without demand meters (like the residential classes), however, the fairest way to recover those demand-related costs is in proportion to a customer's usage of gas. For the PGL HTG class, the cost-of-service study shows that 37% of the non-storage cost of service is demand-related. This means that, under PGL's own cost-of-service study, there is no justification for collecting more than 63% of the cost of service through the customer charge. PGL's existing rates already recover 62% of residential revenues through the customer charge, so there is no justification for a substantial increase in that charge. *Id.* at 15-16. For the NS HTG class, the cost-of-service study shows that 33% of the non-storage cost of service is demand-related. This means that, under North Shore's own cost-of-service study, there is no justification for collecting more than 67% of the cost of service through the customer charge. North Shore's existing rates already recover 68% of residential revenues through the customer charge, so there is no justification for a substantial increase in that charge.

Moreover, the percentages from the cost-of-service study assume that it is proper to recover all distribution-related costs that are classified as customer-related through the customer charge. Traditionally, PGL (and many other gas companies) collected a portion of those customer-related distribution costs. Thus, based on PGL's own cost study, 63% would be the maximum theoretical amount of cost that should be collected through the customer charge for HTG customers. *Id.* at 16. When viewed through facts specific to this case, such as the Companies' guarantee that it will recover its revenue requirement through Rider VBA and other previously identified riders, as well as public policy goals that seek to encourage conservation and energy efficiency, even this 63% level is excessive.

<u>Public Policy Goals Support Rejection of the NS/PGL Rate Design Proposals.</u>

Of course, the Companies have made no secret of why they seek to recover more revenues through the Residential customer charge. When a utility's sales are declining, as appears to be the case with PGL now (at least based on its forecasted test year data), the utility would like to collect more of its revenues through the flat, non-usage based customer charge. Conversely, when a utility's sales are increasing – as was the case for PGL and many gas Companies for several decades -- the utility prefers to have more revenues collected through volumetric charges. Moreover, because natural gas usage is primarily weather-sensitive, the Companies seek to eliminate risk by ensuring a consistent amount of revenues through the flat monthly customer charge. *Id.* at 17. Past Commission orders have responded to utility company claims that revenue stabilization is needed through ever-increasing customer charges. Recently, the Commission has begun to re-think that policy. In the recent Commonwealth Edison Company rate design proceeding, for example, the Commission rolled back the amount of revenues recovered through the customer charge for ComEd, noting in particular that because there is little risk of non-recovery of costs for ComEd because of its adoption of formula rates, a lowering of the percentage of revenues recovered through the customer charge was justified.

In the instant docket, PGL and North Shore have virtually no risk of not recovering their respective revenue requirements going forward. The Companies have three rate mechanisms in place that essentially assure PGL that it will recover approximately the same annual level of residential revenues each year. Rider VBA adjusts PGL's revenue collections for any changes in consumption as compared to the forecasted amount. This is achieved through an annual reconciliation that ensures that the Company receives the revenue requirement for the residential and small commercial customer classes (the vast majority of its customer base) that was established in the last rate case. That is, if revenues in a given class fall below the previously established revenue requirement set by the Commission, surcharges are assessed through Rider VBA in April through December of the following year.

Similarly, Rider SSC essentially assures Peoples Gas that it will collect its storage-related costs, not only by adjusting for actual vs. projected payments for storage within the residential customer class, but even permitting the shifting of costs among classes for differences in storage utilization. *Id.* at 18. In addition, the Company is essentially guaranteed a designated level of revenues for uncollectible accounts through Rider UEA. This rider provides for monthly adjustments to customers' bills for any over- or under-collections of PGL's actual uncollectible accounts expense. *Id.*

The Companies also have begun implementing a new monthly revenue adjustment mechanism called Rider QIP. PGL's Rider QIP was approved by the Commission's final Order in Docket No. 13-0534 and became effective January 1, 2014. Rider QIP allows PGL (and North Shore) to collect a return of and on qualifying infrastructure investments, as defined in new Section 9-220.3 of the Public Utilities Act.

This new rider will ensure that PGL's costs for new distribution facilities in its AMRP program are collected from customers as the facilities are completed, rather than having to wait for the filing and completion of a new distribution rate case. *Id.* at 18-19.

The existence of all of these ratemaking mechanisms are important because they remove any concerns Peoples Gas and North Shore otherwise may have with revenue stability. There simply is no need to have high customer charges to enhance annual revenue stability when Riders VBA, SSC, UEA, and QIP already provide the Companies with those assurances. This revenue stability is consistent with the Commission's recent finding in the aforementioned ComEd rate design case.

Other state commissions have considered the amount of risk of revenue recovery in assessing the need for high customer charges. Mr. Rubin noted that the Minnesota Public utilities Commission assessed revenue recovery risk when considering a revenue decoupling mechanism (like Rider VBA) and the residential customer charge for another natural gas utility. In *CenterPoint Energy Resources,* Docket No. G-008/GR-13-316 (Minn. PUC June 9, 2014), that commission rejected the utility's request for a large increase in the customer charge (from $8.00 to $12.00) and set the customer charge at $9.50 for all residential customers (heating and non-heating). That commission stated: "full revenue decoupling achieves a revenue-stabilization objective that might otherwise be accomplished by an increased customer charge. Both effectively reduce revenue volatility for the Company, protecting its ability to recover fixed costs from unexpected usage variations caused by weather or other factors. Given the protection provided by revenue decoupling, the Commission will not approve the Company's proposed increase …" *Id.* at 51.

The ICC, too, has also recognized that Rider VBA and high fixed charges are redundant ways to address the issue of revenue stability. In its August 30, 2013 Energy Efficiency Report, the Commission stated that because of Rider VBA, "the Commission can provide a mechanism for revenue stability that lowers the monthly customer charges and increases the volumetric charges. Such a change can decrease energy use by providing a greater price signal" to customers. In other words, because of the various adjustment riders in PGL's tariff, it is no longer necessary (assuming for the sake of argument that it ever was necessary) for PGL to have high customer charges. The issue of revenue stability is addressed through the riders; it does not need to be addressed again through the rate design. AG/ELPC Ex. 3.0 at 20.

Other policy implications should be considered by the Commission when examining the customer charge issue in this case. The Illinois General Assembly, in its passage of Section 8-104 of the Public utilities Act, made clear its interest in reducing the amount of natural gas delivered to utility customers and reducing the cost of utility bills that customers pay. Specifically, Section 8-104(c) requires specific reductions in the use of natural gas on an annual basis. As AG/ELPC witness Rubin aptly testified, moving even closer to SFV rates, as Peoples Gas proposes, undermines this public policy objective by reducing the amount of the customer bill that can be reduced through conservation and energy efficiency. AG/ELPC Ex. 3.0 at 20. Giving PGL’s customers more control over their natural gas bills by reducing the customer charge gives customers an important incentive to reduce energy usage.

In the aforementioned ICC Energy Efficiency Report, the Commission recognized that moving away from SFV rates could help the State meet its energy efficiency goals. The Commission, in particular, recognized that reducing the customer charge while increasing variable charges could reduce overall natural gas usage and assist in the achievement of statutory natural gas usage reduction goals in a cost-effective manner. The Commission stated:

> The importance of these findings is that increasing the volumetric distribution charge by even 10% (the distribution charge is approximately 40%-50% of the bill) could lead to a 0.4%-0.5% short term reduction and 0.88%-1.1% long-term reduction in gas use over what it would be with the lower volumetric price. Because altering the volumetric charge does not affect the average cost of delivery service to retail customers (it does affect the costs to individual customers but on average a customer pays the same amount), these

> additional savings can be achieved without increasing the [energy efficiency program] budget limitations. If prices and weather are similar to what was experienced in 2009, one should expect that increasing the volumetric distribution charge by 10% would achieve a usage reduction that is about half of the May 31, 2015 goal of 0.8%.

Id. at 24. Thus, the Commission agreed that enabling customers to have more control over their natural gas bills serves the statutory goal of reducing natural gas consumption in a cost-effective manner.

<u>The Companies' Rate Design Proposals Result in Inequitable Cross-Subsidies</u>

As noted by AG witness Rubin, the Companies' proposed rate design would further shift the burden of revenue collections onto low-use residential customers – an inequity that the Commission has sought to eliminate in recent orders. In discovery, the Companies provided Mr. Rubin with actual billing data for each month of the test year for each of its residential customers. The data set consists of more than 7 million records for Peoples Gas and more than 1 million records for North Shore. AG/ELPC Ex. 3.0 at 4. Using PGL's actual billing data for the test year, Mr. Rubin determined that for Heating customers, annual bill impacts would range from bill reductions (for a few thousand very high-use customers) to increases in excess of 30% (for the more than 30,000 customers using less than 250 therms *per* year). While some of the impacts for very low-use customers might be eliminated if those customers turned out to be Non-Heating customers, there would remain increases in the range of 25% or more for tens of thousands of customers using between 250 and 750 therms *per* year.

The impacts for NS Heating customers are similar to those observed for Peoples Gas. Using North Shore's actual billing data for the historical 2012-2013 year, Mr. Rubin determined that for HTG customers, annual bill impacts would range from bill reductions for more than 24,000 customers (about one in every five customers) to increases in excess of 15% (for the more than 7,000 customers using less than 500 therms *per* year). While some of the impacts for very low-use customers would be eliminated if those customers were NH customers, there would remain increases in the range of 25% for PGL Heating customers and 10% or more North Shore customers for tens of thousands of customers using between 250 and 750 therms *per* year. AG/ELPC Ex. 3.0 at 22, 28.

Roger Colton, a lawyer and economist who has analyzed the impact of utility rates on low-income customers for state agencies, federal agencies and private Companies for more than 20 years, offered testimony on the impact of the North Shore and Peoples Gas rate increase proposals on low-use ratepayers, particularly their effect on low-income gas customers.

Colton's testimony examines the impact on low-use ratepayers of North Shore's proposal to increase its fixed monthly customer charge by 24% and Peoples' plan to increase its own customer charge by 43%, as well as the unfairness of the rate design plans proposed by each utility, which compel low-use customers to subsidize high-use customers. He recommends that both of these proposals be rejected as unreasonable given that these charges impose disproportionate risks on segments of the Companies' customer base that on average use far less gas than other customers and thereby place far less demand on North Shore's and Peoples' gas delivery systems. He proposes that the Commission instead approve the cost-based rate design proposed by AG witness Scott Rubin (AG/ELPC Ex. 3.0) and reduce the monthly customer charge, rejecting the Straight-Fixed Variable rates that have unfairly allocated North Shore's and Peoples' delivery costs and thwarted consumers attempts to control their electric bills.

Colton makes these recommendations in view of statements made by the Companies to the investment community that their financial condition is far more secure than has been represented to this Commission. AG Ex. 4.0 at 31-32. In light of those claims, Colton explains how the need to balance the interests of ratepayers and utility shareholders dictates that low-use customers should not be forced to bear the normal operating and financial risks faced by public utility companies, either through an unfair rate structure or through the recovery of questionable or excessive utility costs. AG Ex. 4.0 at 32-33.

Colton first reports on the fact that the fixed monthly customer charges imposed on North Shore and Peoples ratepayers are outliers in the Illinois utility industry, as noted earlier in this portion of the Brief. Even at current rates, North Shore and Peoples have the highest customer charges in the state of Illinois, at $23.75 and $26.91 respectively. A customer of one of these Companies is being asked to spend these amounts even if they do not consume a single therm of natural gas. AG Ex. 4.0 at 5-6.

AG witness Colton noted that fixed customer charges of this size, combined with the Companies' regressive rate design, impose disproportionately higher percentage increases on low-use customers. Peoples' residential non-heating customer bills will be impacted in inverse proportion to how much gas they use:

PGL Non-Heating Customers,

% Ave. Consumption	Effective Increase	Average Annual Dollar Impact
50%	+7.6%	+$16.80
75%	+5.0%	+$12.19
150%	-0.6%	- $ 1.74

Similarly, Peoples residential heating customers are more burdened by the Company's proposal if they use less gas:

PGL Heating Customers,

% Ave. Consumption	Effective Increase	Average Annual Dollar Impact
25%	+19.2%	+$103.24
50%	+12.2%	+$89.44
150%	+2.3%	+$34.19

The same relationships hold under the North Shore proposal:

NS Non-Heating Customers,

% Ave. Consumption	Effective Increase	Average Annual Dollar Impact
25%	+11.1%	$21.71

50%	+7.8%	$17.69
150%	+0.4%	$ 1.35

NS Heating Customers,

% Ave. Consumption	Effective Increase	Average Annual Dollar Impact
25%	+12.3%	$59.71
50%	+7.2%	$49.84
150%	+0.7%	$10.34

The effective result of these regressive proposals is that non-heating customers with one-sixth the consumption of higher use customers (25% vs. 150%) will pay multiple times more in absolute dollars on an annual basis. Heating customers with one-sixth the consumption of higher use customers (25% vs. 150%) will pay not just more in absolute dollars annually, but multiple times more. AG Ex. 4.0 at 9.

The impact of these pricing structures on low-income customers, Colton observes, is particularly egregious. Low-income customers tend to be, in general, low-use customers, because low-income customers tend to live in substantially smaller housing units than do higher income customers. Colton presented data from the U.S. Department of Energy's 2009 Residential Energy Consumption Survey for the Midwest Census region, which includes Illinois, showing that natural gas consumption increases as income increases, and that higher incomes lead to occupation of larger sizes of housing units. AG Ex. 4.0 at 11-12; AG Ex. 4.1, RDC-5, p.1-3.

Colton's ultimate conclusion is that the Companies' proposed rates and rate designs, if adopted by the Commission, will have a disproportionate impact on low-use customers, many of whom tend to be low-income customers as well, not only because they will absorb a higher percentage of the proposed rate increases the less they consume, but also because they will pay more in absolute dollars. Mr. Colton's findings are yet another reason why the Companies' Residential Rate Design proposals should be rejected.

AG/ELPC Witness Rubin's Rate Design Should Be Adopted by the Commission

To remedy cross-subsidization inequities between low and high users, Mr. Rubin recommended that PGL should move toward collecting no more than 50% of HTG revenues from the customer charges. Under PGL's proposed revenue requirement, these results can be approximated by keeping PGL's customer charges at their existing amounts. Thus, the increase in PGL's proposed increases in the HTG and NH revenue requirements would be collected solely through increases in the volumetric charges.

Mr. Rubin calculated the impact on customer rates of the AG-proposed rates, as is described on AG/ELPC Exhibit 3.3 and 3.4. It can be seen that lower-use customers in each class receive modest rate increases, while those customers who use more gas see greater impacts on their bills, consistent with cost-causation principles.

Again, assuming 100% recover of the Companies' proposed revenue requirements, the AG/ELPC-proposed rate design would collect approximately 52% of PGL's Heating non-storage revenues and 64% of North Shore's Heating non-storage revenues through the customer charges. If approved, this change would start the process of restoring PGL's residential customer charges to more traditional levels. Similar to what was proposed in the Residential Non-Heating section above, in the very likely possibility that the Commission determines that Peoples Gas should receive a lower rate increase than Peoples Gas requested, the rates shown in the above table should be scaled back proportionately so that the HTG customer charge would be designed to collect between approximately 50% and 52% of non-storage revenues for PGL Heating customers and approximately 64% of non-storage revenues for North Shore Heating customers. Approval of the AG/ELPC proposed rate design will rationalize the rate design, give customers more control over their bills (thereby ensuring consistency with the State's energy efficiency goals), and start to alleviate some of the impacts of modified SFV rate design that has been approved to date by the Commission has had on low-income customers that AG witness Colton discusses in his testimony. It should be adopted by the Commission.

<u>The Companies’ Criticisms of AG/ELPC Witness Rubin’s Proposed Rate Design Should Be Rejected by the Commission</u>

In her Rebuttal testimony, Ms. Egelhoff claims that SFV pricing "sends the most accurate price signals about the cost of delivery service" to customers NS-PGL Ex. 29.0 at 3. The Companies are wrong on that point. As noted by AG witness Rubin, SFV pricing, and other pricing schemes that move toward SFV pricing like the Companies' proposals in this case, fail to send customers an accurate signal about the costs associated with serving peak demands for natural gas. Under SFV pricing, each customer in a class (for example, each residential heating customer) would pay exactly the same amount for demand-related costs, even though the customers' demands are vastly different. This phenomenon was highlighted in the examples of the tremendous diversity within the residential class, discussed above and in Mr. Rubin’s Direct testimony. AG Ex. 9.0 at 2.

The Companies claim that essentially all of the Companies' costs are fixed and should be recovered through fixed charges (NS/PG: Ex. 29.0 at 7, 11), that assertion is inaccurate. A gas distribution system is designed to serve the anticipated peak demands and energy requirements of all customers. Very little if any of that investment is actually "caused" by a single customer. When discussing the principle of cost causation, AG witness Rubin explained, ". . . we're actually talking about a fair way to allocate shared costs among customer classes and customers." AG Ex. 9.0 at 2.

When the Companies allocate costs among customer classes in a cost-of-service study, they recognize the shared nature of these common costs. The Companies allocate those costs to each customer class in a way that we find to be fair to all customers. For example, as NS-PGL witness Hoffman Malueg discusses in her rebuttal testimony (NS-PGL Exhibit 28.0), there are good reasons for allocating the cost of distribution mains based on the average and peak approach which recognizes that mains serve both peak demands and annual energy usage. That is, the allocation of a shared cost (or facility) uses energy usage and/or peak demand to have each customer class pay its fair share of jointly used facilities. AG Ex. 9.0 at 3.

As AG witness Rubin explained, that same principle needs to apply when rates are designed. It makes no sense to say that the cost of serving residential customers is based, in part, on demand and energy usage; but then to design rates that ignore demand and energy usage (as SFV rates would do).

Under SFV pricing, each residential customer would pay exactly the same amount toward the cost of mains. In contrast, under a rate design that mimics the way in which costs are fairly allocated to classes (which is what is meant by cost causation), rates would recognize that the "cost increase" (a shorthand expression for the increase in costs allocated to the class) was caused by just one customer. If the costs of mains are collected based on a customer's energy consumption or demands, then the customer whose consumption doubled would pay most (or ideally all) of the cost increase. That is exactly what happens under a traditional rate design that collects demand-related costs either through a demand charge (when demand metering is in place) or through an energy charge (when demand-metering is not feasible).

A rate design that is consistent with the cost-of-service study's allocation methodology – provides a fair result to all customers. The customer who caused the residential class's cost allocation to increase bears the responsibility for those increased costs. Other customers, whose demands and energy usage did not change, are not asked to subsidize the high-use / high-demand customer.

The Companies propose greater movement toward SFV pricing. This would have the effect of requiring lower-use / lower-demand customers to provide tremendous subsidies to higher-use / higher-demand customers. In contrast, the rate design Mr. Rubin proposes for the residential classes tries to mimic the way in which costs are allocated to the residential class, so that subsidies among residential customers are minimized.

NS/PGL witness Egelhoff further suggests that “SFV rate design reduces the volatility of customers' bills.” NS/PGL Ex. 29.0 at 4. But this is not a legitimate reason to move toward SFV rates. First, Ms. Egelhoff assumes that customers want their bills to be the same all year. There is no evidence that is the case. Even if one assumes they do, then they can enroll in a budget billing plan. Mr. Rubin points out that, in fact, not all customers want this. Some customers want their gas bills to be low in the summer because they incur other expenses in the summer (such as increased electricity costs for air conditioning, or increased child care costs when school is out). Second, Ms. Egelhoff confuses leveling a customer's bill with subsidizing customers through the rate design. It is one thing to offer a customer the option of spreading their annual bill over 12 months. It is quite another to relieve high-use customers of the cost of serving them by having low-use customers pick up the tab. SFV pricing does not just "reduce the volatility of customers' bills"; it also requires low-use customers to pay costs that are incurred to serve higher-use customers. It is grossly unfair and can result in tremendous cross-subsidies within a class.

In the Companies’ last case, part of this unfairness was corrected when the Companies separated non-heating customers from the rest of the residential class. The rates for those very low-use customers were reduced dramatically as a result of their no longer being required to subsidize the demand-related costs of high-use heating customers. The inequity of SFV-type rates, however, remains within the residential heating class. Lower-use heating customers are subsidizing the bills of higher-use heating customers, as Mr. Rubin demonstrated in his direct testimony and as described earlier in this Brief. Moreover, the level of subsidy increases under the Companies' proposal to move even closer to SFV rates by significantly increasing the customer charge.

Other criticisms of AG/ELPC witness Rubin's proposed rate design fall flat. Ms. Egelhoff asserts that because "irrespective of a customer's demand on the peak day, lower usage on other days would reduce the customer's contribution to demand cost recovery" NS/PGL Ex. 29.0 at 8. As pointed out by AG/ELPC witness Rubin, Egelhoff's criticism is valid, but she fails to finish the thought. It is true that the rate design method Mr. Rubin uses is imprecise because it assumes that peak demand is strictly proportional to annual energy usage. Clearly, that is not exactly precise. But Ms. Egelhoff fails to compare this imprecision to her support of SFV rates. An SFV rate design wrongly assumes that the demand-related costs for all residential customers are exactly the same. Mr. Rubin's approach is imprecise because of the limits of current metering technology and other implementation factors. Ms. Egelhoff's method just assumes away the problem and is inconsistent with reality. As Mr. Rubin explained, we know that for most customers within a class, demands bear a pretty close relationship to annual usage. It is not exact, but a customer who averages 200 therms *per* month is going to have much higher peak demands than a customer who uses only 200 therms in an entire year. That is certain. AG/ELPC Ex. 9.0 at 7-8.

Finally, Staff witness William Johnson has recommended that the fixed cost be set at approximately 65%, based on a strict allocation of demand-related costs to variable charges. Staff Ex. 4.0 at 46-48. While this is an improvement over the NS/PGL proposals, it does not go far enough in recognizing other public policy considerations related to rate design, such as equity (avoidance of cross subsidies from low users to high users) and public policy goals related to promoting conservation and energy efficiency.

Staff witness Johnson complained in his Rebuttal testimony that it is unclear how Mr. Rubin derived the figures of 50% and 75%, respectively, for fixed cost recovery in heating and non-heating rates (Staff Ex. 9.0 at 24), and why some customer costs should be recovered through variable charges, rather than the customer charge. But that criticism should be given little weight. As Mr. Rubin explained in his Direct testimony, there are public policy reasons why more costs should be recovered through variable *per*-therm charges than a strict application of placing all customer-related costs, which amount to 63% of costs, in the customer charge.

The facts in this case, which make clear that the Companies have zero risk of not recovering their revenue requirement given the number of riders that have been authorized for the Companies pursuant to statute and Commission order, support a greater shift away from the SFV-like customer charges that have created the extreme inequities highlighted in Mr. Rubin's direct testimony exhibits 3.3 and 3.4. This case provides the opportunity to correct those inequities. Public policy goals of promoting conservation and energy efficiency, which are clearly articulated in Section 8-104 of the

Act and the Commission's recent rate design orders and reports, also support moving away from precise adherence to cost study data.

Mr. Rubin's rate design is consistent with the Companies' own cost study allocations, gives customers more control over their bills (thereby ensuring consistency with the State's energy efficiency goals), and begins to alleviate some of the impacts of modified SFV rate design that have detrimentally impacted low-income customers. The record evidence and recent Commission rate design orders and ICC Report findings support its adoption by the Commission

Commission Analysis and Conclusion

The Commission finds that the Companies proposed increases in the customer charges pursuant to its SFV-based rate design are inconsistent with public policy as discussed in Section IX, B 2 (Fixed Cost Recovery) of this order. The Commission finds that Staff's and Intervenor's arguments in favor of assigning demand based costs to volumetric charges are consistent with energy efficiency and the avoidance of cross subsidies. The Commission accepts Staff's rate design proposal for this customer class, which reflects a more traditional rate design whereby customer charges recover embedded cost-of-service ("ECOS") study customer costs and distribution charges recover ECOS study demand costs. Therefore, customer's bills are more closely aligned with the ECOS study. The customer charges for the S.C. No. 1 Small Residential Service, Heating class should be set to recover the final Commission approved ECOS studies' customer costs. The remaining, non-storage related demand costs, would be recovered through a flat distribution charge on a per therm basis.

c. Service Classification No. 2, General Service

Companies' Position

The Companies stated that, consistent with the rate design objectives and principles applicable to fixed cost recovery, they each proposed to continue to set S.C. No. 1 HTG at cost. NS Ex. 15.0 at 10; PGL Ex. 15.0 REV. at 10. North Shore proposed to recover 80% and Peoples Gas proposed to recovery 75% of non-storage related fixed costs through the customer charge with all remaining non-storage costs being recovered through a flat distribution charge. Each would continue to recover storage-related costs under Rider SSC. NS Ex. 15.0 at 12; PGL Ex. 15.0 REV. at 12. The Companies contend that their proposals are consistent with the Commission policy for gas Companies of gradually increasing fixed cost recovery in fixed charges. To retreat from this gradual movement, as AG/ELPC and Staff proposed, exacerbates the extent to which a customer's bill does not reflect the costs it causes the Companies to incur, *i.e.*, customer usage would drive fixed cost recovery but usage does not drive the Companies' incurrence of those fixed costs.

Staff's Position

Staff argues that the Commission should accept Staff's S.C. No. 2 General Service classes' rate design proposal for North Shore and Peoples Gas.

Staff reiterates that recent Commission orders have been moving towards aligning customers' bills with the cost of service (i.e., customer charges based upon ECOS study customer costs and distribution\demand charges based upon ECOS study demand costs). While the Companies' proposed S.C. No. 2 General Service class customer charge recovers 100% of ECOS customer costs, it also recovers demand related costs. This is a shift towards greater SFV-based rate design and is, thus, problematic. The Commission has recently been making adjustments that move away from SFV-based rate designs for those electric companies that have adopted formula rates through EIMA. Similar to the impact of electric companies' formula rates, the Company's implementation of Rider VBA provides revenue stability and eliminates the need to have an SFV-based rate design. Also, increasing the percentage of non-storage related demand costs through fixed charges lowers the percentage of non-storage related demand costs recovered through the per therm distribution charge. This, in turn, could discourage conservation. Staff Ex. 4.0 at 33-34. Finally, Staff found that moving ECOS study-based demand costs that are allocated to customer classes based upon demand into a fixed customer charge shifts cost responsibility to customers with lower demands. This occurs because rather than collecting total demand related costs on a per therm basis, some of the demand related costs are collected on a per customer basis. The per therm charge is lower than it would have been if all demand related costs were recovered on a per therm basis and the customer charge is higher than it would have been if the demand costs were collected through a per therm charge (for example, a customer that uses zero therms would pay for some of the demands that a larger use customer places on the system). *Id.*

Staff's proposed S.C. No. 2 General Service class customer charge for all three meter classes (for each Company) will recover 100% of ECOS study-based customer costs. Consistent with the most recent Commission orders concerning movement away from SFV-based rate designs, Staff witness Johnson proposes a decrease in the percentage of non-storage related demand costs currently recovered through the customer charge for all three meter classes. His proposal provides a gradual shift away from SFV-based rate design while taking into consideration customer bill impacts and revenue stability for the Company. Specifically, Staff proposes the percentage of non-storage related demand costs recovered through the customer charge for North Shore for Meter Classes 1 and 2 be decreased by 10% from the current Commission approved 45%. The resulting percentage of non-storage related demand costs recovered through North Shore's customer charge for Meter Classes 1 and 2 would be 40%. The same 10% decrease for North Shore's Meter Class 3 would result in a decrease in the percentage of non-storage related demand costs recovered through the customer charge from 35% to 31%. The remaining non-storage related demand costs would be recovered through the Company's proposed declining two-block distribution charge on a per therm basis. Staff Ex. 4.0 at 35-36 and Schedule 4.01N.

For Peoples Gas, Staff proposes the percentage of non-storage related demand costs recovered through the S.C. No. 2 General Service class customer charge for Meter Classes 1, 2, and 3 be decreased by 10% from the current Commission approved 40%, 45%, and 10%, respectively. The resulting percentage of non-storage related demand costs recovered through the customer charge for Peoples Gas would be 36% for Meter Class 1, 40% for Meter Class 2, and 9% for Meter Class 3. The remaining non-storage related demand costs would be recovered through the Company's proposed declining two-block distribution charge on a per therm basis. *Id.* at 54-55 and Schedule 4.01P.

Staff also recommends that, going forward, the Commission make additional adjustments to the percentage of non-storage related demand costs recovered through the S.C. No. 2 General Service class customer charge until the customer charges per meter class recover only ECOS study customer costs for both Companies. Staff is not recommending that a set percentage in each case or time period be utilized to eliminate the non-storage related demand costs from the customer charge going forward. The amount of the adjustments should be decided in each case in order to consider bill impacts for customers. Staff Ex. 4.0 at 36. Recent Commission Orders indicate a movement away from SFV-based rate designs, especially for those Companies with cost recovery mechanisms in place (like the Companies' Rider VBA) that provide revenue stability. Staff's rate design proposal makes a similar movement while taking rate impacts into consideration. Staff Ex. 9.0 at 14.

Commission Analysis and Conclusion

The Commission's recent Orders in ComEd (Docket No. 13-0387) and Ameren Illinois (Docket No. 13-0476) make it clear that SFV-based rate designs should be re-examined and rate design should reflect traditional rate design principles, which more closely align customers' bills with the ECOS study. The Commission is actively reevaluating how rate design can be utilized to ensure that customers are responsible for the demands they place on the system and that rate design maximizes conservation efforts.

With this in mind, the Commission finds that the Companies' proposed increases in the S.C. No. 2 General Service class customer charges pursuant to its SFV-based rate design are inconsistent with public policy as discussed in Section IX, B 2 (Fixed Cost Recovery) of this order. Customer charges for these classes should be set at the levels discussed above, and the remaining non-storage related demand costs should be recovered through the Companies' proposed declining two-block distribution charge on a per therm basis.

This proposal results in a gradual movement away from SFV-based rates for the S.C. No. 2 General Service classes while taking into consideration customer bill impacts and revenue stability for the Companies. Going forward, the Commission directs the Companies to make additional adjustments to the percentage of non-storage related demand costs recovered through the customer charge until the customer charges per meter class recover only ECOS study customer costs. However, this should be done while taking into consideration bill impacts for the customers in the various meter classes.

d. Service Classification No. 4, Large Volume Demand Service

Companies' Position

The Companies stated that, consistent with the rate design objectives and principles applicable to fixed cost recovery, they each proposed to continue to set S.C. No. 4 at cost. NS Ex. 15.0 at 10; PGL Ex. 15.0 REV. at 10. Each proposed to set the monthly customer charge at cost. For North Shore, Companies witness Ms. Egelhoff stated that the demand charge would recover 70% of non-storage related demand costs and the distribution charge would recover all remaining non-storage related demand costs. For Peoples Gas, Ms. Egelhoff stated that the demand charge would continue to recover 55% of non-storage related demand costs and the distribution charge would recover all remaining non-storage related demand costs. For each, storage related costs would be recovered under Rider SSC. NS Ex. 15.0 at 19; PGL Ex. 15.0 REV. at 19.

Staff's Position

Staff believes that the Commission should accept Staff's S.C. No. 4 rate design proposal. The Companies are proposing to set the monthly customer charge at cost to recover all ECOS study customer costs. The customer charge increases from $594 to $656 *per* month for North Shore and the $687 to $982 for Peoples Gas. The proposed demand charge increases from 55.277 cents *per* therm of billing demand to 67.695 cents *per* therm for North Shore and 71.421 cents *per* therm of billing demand to 99.482 cents *per* them for Peoples Gas. The distribution charge recovers the remaining non-storage related demand costs for both Companies. NS Ex. 15.0 at 19 and PGL Ex. 15.0REV. at 19.

Staff witness Johnson has no objection to the Company's rate design proposal for the S. C. No. 4 rate class. The Company is proposing to set the customer charge at cost, which is a minimal part of a customer's bill because customers must use an average of over 41,000 therms *per* month and the customer charge would represent a minimal part of the total bill. The remaining revenues are collected through the demand and distribution charges and the S.C. No. 4 class proposal will recover its full cost of service. However, Mr. Johnson does propose that if the Company's total customer charge revenues derived from the proposed customer charge ($656 NS and $982 PGL) are greater than the customer costs found on the final Commission approved ECOS study, then the final customer charge should be lowered to recover ECOS study customer costs only. Staff Ex. 4.0 at 43.

IIEC's Position

IIEC witness Brian Collins proposes an across the board increase for all classes. IIEC Ex. 1.0 at 3; IIEC Ex. 3.0 at 18-19.

Commission Analysis and Conclusion

The Commission finds that the Company's rate design proposal for the S. C. No. 4 rate class is reasonable and hereby approves it. The Commission reiterates its rejection of the proposed across the board increase in rates which as discussed above is not supported by the record.

3. Classification of SC No. 1 Residential Heating and Non-Heating Customers

Companies' Position

In response to AG/ELPC's claims that a large number of North Shore and Peoples Gas S.C. No. 1 customers appeared to be misclassified between heating and non-heating, the Companies showed that the AG/ELPC analysis was flawed because it focused on usage as the basis for determining if a customer uses gas for space heating, and the Companies' approach of classifying customers based on their gas appliances is more accurate. As Companies witness Mr. Robinson showed, there are often good explanations for why a customer's usage may vary from an expected level. NS-PGL Ex. 32.0 at 4-7. This is why the Companies focus on the customer's appliances and not usage to determine if the customer is an S.C. No. 1 NH or HTG customer. *Id.* at 3, 6.

The Companies explained that they have long-standing processes, pre-dating the introduction of S.C. No. 1 non-heating and heating rates, to identify the customer's appliances. These processes include inquiries when an applicant or customer interacts with a customer service representative and a physical inspection of the premises. *Id.* at 7-8. A sample of data on which the AG witness relied that the Companies reviewed showed that, overwhelmingly and to the extent they had definitive data, customers were correctly classified. While it is certainly possible that some customers are misclassified, it is not likely that 100% accuracy, 100% of the time is achievable, even if the Companies conducted the study that Staff suggested. NS-PGL Ex. 46.0 at 5.

When the utility changes out or installs a meter, this requires a physical inspection of the premises and a verification of appliances. NS-PGL Ex. 32.0 at 7. If a customer is seeking LIHEAP funding but his account is a non-heating account, this will trigger a physical inspection to verify the appliances, as non-heating accounts are not eligible for LIHEAP. *Id.* at 8.

For new construction, the Companies will work with the contractor to ascertain the appliances that will be at the premises. This is necessary for the utility to determine the pipe to install, meter size and other information needed to establish service. In many cases, if utility personnel are at a premise, they inspect and note the appliances, which are then updated in the Companies‟ system. For example, if utility personnel are responding to a gas odor complaint, they will catalog the appliances. These processes help keep the Companies‟ records current and accurate. Certainly, some customers may be misclassified. However, using appliances as the criterion to determine whether a S.C. No. 1 customer is a heating or non-heating customer and the many methods that the Companies use to keep track of appliances at each customer location help ensure a high level of accuracy in classifications. *Id.*

In response to Staff, the Companies stated that, in the limited time available, they were unable to develop a sound cost estimate for a study of classifications, but they explained that the large number of accounts that could require intensive manual review or physical inspections of the premises, or both, suggests that the costs of an in-depth study would almost certainly be millions of dollars and a large commitment of personnel and time. The Companies further explained that, given the existing processes and the large number of customers already subject to review on an annual basis as part of the application process, a study is not needed. *Id.* at 2-4.

Companies' witness Robinson responded in surrebuttal testimony to Staff's recommendation to give a rough estimate of the amount of time it would take to carry out an in-depth study and an estimate of the costs involved. Mr. Robinson stated that subject to the limitations of developing the requested estimates in a short period, the Companies' rough estimate of the number of accounts that would potentially be inspected is approximately 580,000. This estimate is based on information from the Companies' customer information system on the number of premises that did not show a physical verification of appliances in the last three years. The Companies were not able, in the time available, to estimate the costs of further manual review of accounts after the initial query. However, given the large number of accounts, and the need for manual review, physical inspections (possibly including repeat visits when the Companies could not initially gain access to identify all appliances), or both, it would almost certainly be millions of dollars. NS-PGL Ex. 46.0 at 3-4.

Mr. Robinson stated that the Companies do not think a requirement to conduct a study is needed. The Companies rely on identification of gas appliances to categorize a customer as heating or non-heating. They have long-standing processes, pre-dating the introduction of heating and non-heating rates in S.C. No. 1, to identify the customer's appliances. These processes involve both inquiries when an applicant or customer interacts with a customer service representative or a physical inspection of the premises. The application process alone typically involves tens of thousands of applicants in a year. This means that, at a minimum, the Companies are verifying appliances for a large percentage of their customer base every year. Because the inquiries focus on appliances and on following up when the applicant's or customer's description of his appliances does not mesh with existing data that the Companies have about the premises, these existing processes are very effective in correctly categorizing customers. *Id.* at 4.

Companies witness Robinson proposed an alternative to a study or investigation. He stated that it is his understanding that after a rate case order, the Companies must communicate with customers about the rate case. They could use that communication to emphasize to S.C. No. 1 customers the significance of the "heating" and "non-heating" designations and encourage customers to call with questions or concerns. *Id.* at 5.

Staff's Position

AG/ELPC witness Rubin testified that there may be residential customers who are misclassified as between heating and non-heating. AG/ELPC Ex. 3.0 at 3. He states that if customers are misclassified between heating and non-heating classes there could be a large difference in the bills they pay. The AG/ELPC recommends that the Companies investigate and improve the classification of residential customers and report back to the Commission on its findings.

Staff witness Johnson opined that the Commission approved the Companies' establishment of residential heating and non-heating classes in Docket Nos. 12-0511/12-0512 (Consol.). He stated that AG/ELPC witness Rubin does not appear to disagree with the "heating" and "non-heating" sub-classes *per se*, but rather wants to make sure that the customers are classified correctly as heating or non-heating. The Companies' tariffs specifically designate "Heating Customers" as customers who use gas as their principal source of space heating requirements and "Non-Heating Customers" as customers who do not use gas as their principal source of space heating requirements. (North Shore ILL.C.C.No. 17, Ninth Revised Sheet No. 6 and Peoples Gas ILL.C.C.No. 28, Ninth Revised Sheet No. 5.) Staff has no objection to the Companies' designations for these customers found in the tariffs. Staff Ex. 9.0 at 21.

However, because the Commission only approved the bifurcation of the residential class into heating and non-heating classes in Docket No. 12-0511/12-0512 (Consol.), dated June 18, 2013, Mr. Johnson understands why AG witness Rubin would want to make sure that customers are classified correctly. Staff witness Johnson stated that he had no objection to the Commission ordering the Companies to do an in-depth study to make sure that "heating" and "non-heating" customers are classified correctly. However, he emphasized that the Commission should also consider that this will probably involve some on-site inspections that will likely include additional costs.

AG's Position

AG/ELPC witness Rubin testified that there may be residential customers who are misclassified as between heating and non-heating. He states that if customers are misclassified between heating and non-heating classes there could be a large difference in the bills they pay. He gives an example of the rate difference between classifications for Peoples Gas. The non-heating customer charge under present rates is $13.60 *per* month and the *per* therm delivery charge is $0.42032. The heating customer charge is $26.91 *per* month and the *per* therm delivery charge is $0.18885. The AG/ELPC recommends that the Companies investigate and improve the classification of residential customers and report back to the Commission on its findings. AG/ELPC witness Rubin further recommends that if the Companies cannot complete the process by the close of the record in this case, or if they refuse to undertake the task, then the Commission should order the Companies to do so as quickly as possible following the conclusion of this case.

If a customer is seeking LIHEAP funding but his account is a non-heating account, this will trigger a physical inspection to verify the appliances, as non-heating accounts are not eligible for LIHEAP.

For new construction, the Companies will work with the contractor to ascertain the appliances that will be at the premises. This is necessary for the utility to determine the pipe to install, meter size and other information needed to establish service. In many cases, if utility personnel are at a premises, they inspect and note the appliances, which are then updated in the Companies‟ system. For example, if utility personnel are responding to a gas odor complaint, they will catalog the appliances. These processes help keep the Companies‟ records current and accurate. Certainly, some customers may be misclassified. However, using appliances as the criterion to determine whether a S.C. No. 1 customer is a heating or non-heating customer and the many methods that the Companies use to keep track of appliances at each customer location help ensure a high level of accuracy in classifications. *Id.*

Commission Analysis and Conclusion

The Commission finds that the Companies suggestion that in the Companies communication with customers about the rate case, they include information emphasizing to S.C. No. 1 residential heating and non-heating customers the significance of the "heating" and "non-heating" designations and encourage customers to call with questions or concerns or to request an inspection. The Commission directs the Companies to submit the content and format of the proposed heating/ non-heating classification communication to Commission Staff for its input and approval prior to its distribution to customers. The Commission further directs the Companies in preparation for their next rate cases to provide in direct testimony the number of customer contacts that are generated by this communication and the number of inspections and account reclassifications that occur as a result.

D. Other Rate Design Issues

1. Terms and Conditions of Service

a. Service Activation

Companies' Position

Based on a cost study, the Companies proposed changes to some of their Service Activation Charges, which recover a portion of the costs related to initiating gas service at a premises. North Shore proposed no change to its succession turn-on charge, $50.00 for a straight turn-on, and $12.00 for relighting each appliance over four. NS Ex. 15.0 at 20-21; NS Ex. 15.8. Peoples Gas proposed $23.00 for a succession turn-on, $38.00 for a straight turn-on, and $13.00 for relighting each appliance over four. PGL Ex. 15.0 REV. at 20-21; PGL Ex. 15.8 REV.

Staff's Position

The Companies identify two types of service activations. A succession turn-on occurs when a customer who is moving out of a home or building calls to discontinue gas service at approximately the same time as the applicant moving in calls and requests gas service. In this instance, only one meter reading is taken. A straight turn-on occurs when there has never been gas service at a location, or when the prior customer canceled service before the new applicant calls to request service and the gas has actually been turned off. In this instance, the gas has to be turned on and appliances have to be relit. NS Ex. 15.0 at 20 and PGL Ex. 15.0 at 20-21.

North Shore prepared an analysis that identifies the costs associated with a succession turn-on, straight turn-on, and the cost to light an additional appliance over four (Included in any reconnection charge is the relighting of a maximum of four gas appliances *per* account). NS Ex. 15.0 at 20. North Shore's analysis shows that the cost for a succession turn-on is $23.74, the cost of a straight turn-on is $64.07, and the cost to light an additional appliance over four is $16.55. NS Ex. 15.8. North Shore is proposing that the straight turn-on be increased from $42.00 to $50.00, and the cost for relighting any appliances over four be increased from $10.00 to $12.00. North Shore is proposing to leave the succession turn-on charge at $20.00. NS Ex. 15.0 at 21.

PGL prepared an analysis that identifies the costs associated with a succession turn-on, straight turn-on, and the cost to light an additional appliance over four (Included in any reconnection charge is the relighting of a maximum of four gas appliances *per* account). NS Ex. 15.0 at 21. PGL's analysis shows that the cost for a succession turn-on is $25.89, the cost of a straight turn-on is $63.42, and the cost to light an additional appliance over four is $17.23. PGL Ex. 15.8. PGL is proposing that the succession turn-on be increased from $18.00 to $23.00, the straight turn-on be increased from $30.00 to $38.00, and the cost for relighting any appliances over four be increased from $10.00 to $13.00. PGL Ex. 15.0 at 21.

Staff witness Johnson has no objection to the Companies' proposals for Service Activation Charges. He stated that they have provided cost break-downs for the various Service Activation Charges and in the interest of gradualism, are not proposing full cost recovery in this proceeding. Staff Ex. 4.0 at 66.

Commission Analysis and Conclusion

The Commission finds that the Companies' proposal for Service Activation Charges is reasonable. The Commission approves the proposal.

b. Service Reconnection Charges

Companies' Position

Based on a cost study, the Companies proposed changes to some of their Service Reconnection Charges, which they assess customers whose gas has been turned off (*e.g.*, disconnections for non-payment or at the customer's request). Each customer receives a waiver of one reconnection charge each year for reconnection at the meter, except where the customer voluntarily disconnects and then requests reconnection within twelve months. North Shore proposed no change for reconnection at the meter, $180.00 when the meter has to be reset, $500.00 when service has to be reconnected at the main, and $12.00 to relight each appliance over four. NS Ex. 15.0 at 21-22; NS Ex. 15.8. Peoples Gas proposed $94.00 for reconnection at the meter, $188.00 when the meter has to be reset, $500.00 when service has to be reconnected at the main, and $13.00 to relight each appliance over four. PGL Ex. 15.0 REV. at 21-22; PGL Ex. 15.8 REV.

Staff's Position

A service reconnection charge is applicable to customers, whose gas has been turned off for any number of reasons, including disconnections for non-payment of bills and at the customer's request. However, each customer is granted a waiver of one reconnection charge each year for reconnection at the meter, except in the situation where the customer voluntarily disconnects and then requests reconnection within twelve months. The Companies offer three types of service reconnections following an involuntary disconnection for which the Companies currently charge customers: basic reconnections which only require a meter turn-on, reconnections which require setting a new meter, and reconnections that involve excavating at the main. NS Ex. 15.0 at 21; PGL Ex. 15.0 at 21.

North Shore prepared an analysis that identifies the costs associated with the three service reconnections (basic reconnections, reconnections which require a new meter set, and reconnections that involve excavations at the main). NS Ex. 15.0 at 21. North Shore's analysis shows that the cost for a reconnection at the meter (basic reconnection) is $90.72, the cost for a reconnection when the meter has to be reset is $200.46, and the cost for a reconnection at the main is $1,638.63. NS Ex. 15.8. North Shore is proposing that the basic reconnection charge remain at $75.00, the cost for reconnection when the meter has to be reset increased from $150.00 to $180.00, and the cost for reconnection at the main increased from $425.00 to $500.00. The Company is also proposing that the charge for relighting each appliance over four will be increased from $10.00 to $12.00, as with the Service Activation Charge. NS Ex. 15.0 at 21-22.

PGL also prepared an analysis that identifies the costs associated with the three service reconnections (basic reconnections, reconnections which require a new meter set, and reconnections that involve excavations at the main). PGL Ex. 15.0 at 21. PGL's analysis shows that the cost for a reconnection at the meter (basic reconnection) is $112.33, the cost for a reconnection when the meter has to be reset is $439.80, and the cost for a reconnection at the main is $1,338.72. PGL Ex. 15.8. PGL is proposing that the basis reconnection charge increase from $75.00 to $94.00, the cost for reconnection when the meter has to be reset increased from $150.00 to $180.00, and the cost for reconnection at the main increased from $425.00 to $500.00. The Company is also proposing that the charge for relighting each appliance over four will be increased from $10.00 to $12.00, as with the Service Activation Charge. NS Ex. 15.0 at 21-22.

Staff witness Johnson has no objection to the Companies' proposals for Reconnection Charges. He states that the Companies have provided cost break-downs for the various Service Activation Charges and in the interest of gradualism, are not proposing full cost recovery in this proceeding. Staff Ex. 4.0 at 68.

No other parties addressed this issue.

Commission Analysis and Conclusion

The Commission finds that the Companies' proposal for Reconnection Charges is reasonable. The Commission approves the proposal.

c. Second Pulse Data Capability Charge

Companies' Position

A customer with certain metering devices may choose to have the Companies enable second pulse capability. Based on cost studies, the Companies proposed to decrease the Second Pulse Data Capability charge from $14.00 to $10.25 (North Shore) and to $10.60 (Peoples Gas). NS Ex. 15.0 at 22; NS Ex. 15.12; PGL Ex. 15.0 REV. at 22; PGL Ex. 15.12. The Companies agreed with Staff's proposal to update the charges using the rate of return that the Commission approves. NS-PGL Ex. 29.0 REV. at 24.

Staff's Position

A customer that has installed an operational meter, meter corrector, or daily demand measurement device capable of providing a second pulse for further data collection capability may choose to have the Companies enable this capability on the meter or device for a monthly charge. NS Ex. 15.0 at 22 and PGL Ex. 15.0 at 22.

The Companies provided analyses of the determination of Second Pulse Capability Charges. NS Ex. 15.12; PGL Ex. 15.12. The analysis for North Shore identified that the monthly charge for Second Pulse Data Capability would be $10.25, a decrease from the current charge of $14.00. The analysis for Peoples Gas identified that the monthly charge for Second Pulse Data Capability would be $10.60, a decrease from the current charge of $14.00. *Id.*

Staff witness Johnson stated that he had no objection to the Companies' proposals for Second Pulse Data Capability Charges. However, the Companies have incorporated a rate of return of 7.02% in the calculation of the charge that is based upon the

Companies' proposed rate of return. Mr. Johnson recommends the charge be recalculated with the final Commission approved overall rate of return in this proceeding. In response to Staff Data Requests, the Companies stated that they agree that it would be appropriate to update the calculation using the approved overall rate of return set by the Commission in its final Order. Staff Ex. 4.0 at 69.

No other parties addressed this issue.

Commission Analysis and Conclusion

The Commission approves the Companies' proposals for Second Pulse Data Capability Charges recalculated using the final Commission approved overall rate of return in this proceeding.

2. Riders

a. Rider 5, Gas Service Pipe

The Companies proposed clarifying language concerning installation and cost responsibility for service pipe and an editorial change to Rider 5, Gas Service Pipe. In particular, the Companies proposed that the pipe installation will meet certain location requirements when practicable and, if it is not practicable and if the reason is not a customer's request or other circumstance for which the customer bears cost responsibility, then the full installation is at the company's expense. NS Ex. 15.0 at 26 27; PGL Ex. 15.0 REV. at 26-27.

The Commission approves the Companies' proposed clarifying language concerning installation and cost responsibility for service pipe and an editorial change to Rider 5, Gas Service Pipe.

b. Rider SSC, Storage Service Charge

The Companies are proposing a change in the *per* therm charge for the storage service charge resulting from the new revenue requirements proposed in this proceeding. NS Ex. 15.0 at 22; PGL Ex. 15.0 Rev. at 22-23. No party objected to the Companies' proposals.

The Commission approves the Companies' proposed change in the *per* therm charge for the storage service charge resulting from the new revenue requirements proposed in this proceeding.

c. Rider QIP, Qualifying Infrastructure Plant [PGL]

Staff and Peoples Gas agree that language changes to Rider QIP should be made to allow for an adjustment through the Rider QIP surcharge if its 2014 actual additions are different than the amount approved in the instant case. NS-PGL Ex. 29.0 at 24-27; NS-PGL Ex. 29.1; Staff Ex. 6.0 at 14. Further, Staff and the Company are in agreement for the need for a findings and ordering paragraph to be included in the Commission's Order concerning Rider QIP. If the Commission's conclusion accepts the AG adjustment to the projected level of 2014 AMRP plant additions recoverable through Rider QIP, the language is as follows:

> Peoples Gas shall reflect in its Rider QIP Surcharge Percentage following the date of this Order the variance from the 2014 QIP amounts included in base rates to its actual 2014 QIP amounts, which may be an increase or decrease to the amount to be recovered through the Rider QIP Surcharge Percentage. The 2014 QIP amounts included in base rates are comprised of $115,986,348, less a negative amount of $33,721,806 for accumulated depreciation and less a positive amount of $8,603,652 for accumulated deferred income taxes, and $1,728,342 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired.

NS-PGL Ex.37.5 P at 3-4; NS-PGL Ex. 43.0 REV.

If the Commission's conclusion rejects the AG adjustment to the projected level of 2014 AMRP plant additions recoverable through Rider QIP and instead accepts Peoples Gas' position, the language is as follows:

> Peoples Gas shall reflect in its Rider QIP Surcharge Percentage following the date of this Order the variance from the 2014 QIP amounts included in base rates to its actual 2014 QIP amounts, which may be an increase or decrease to the amount to be recovered through the Rider QIP Surcharge Percentage. The 2014 QIP amounts included in base rates are comprised of $173,237,532, less a negative amount of $58,686,380 for accumulated depreciation and less a positive amount of $16,463,375 for accumulated deferred income taxes, and $2,620,588 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired.

NS-PGL Ex. 22.14 P; NS-PGL Ex. 43.0 REV.

The Commission approves the Companies' proposed language changes to Rider QIP to allow for an adjustment through the Rider QIP surcharge if its 2014 actual additions are different than the amount approved in the instant case.

d. Rider UEA, Uncollectible Expense Adjustment, and Rider UEA-GC, Uncollectible Expense Adjustment – Gas Costs

The Companies each proposed revising Rider UEA-GC to reflect the proposed Uncollectible Factors arising from data in this case and Rider UEA to reflect the updated uncollectible amount to be recovered in base rates based on the final revenue requirements determined by the Commission in these cases. NS Ex. 15.0 at 25-26; NS Ex. 15.11; PGL Ex. 15.0 REV. at 25-26; PGL Ex. 15.11.

The Commission approves the Companies' proposed revision of Rider UEA-GC to reflect the proposed Uncollectible Factors arising from data in this case and Rider UEA to reflect the updated uncollectible amount to be recovered in base rates based on the final revenue requirements determined by the Commission

e. Rider VBA, Volume Balancing Adjustment, percentage of Fixed Costs

The Companies' proposed revenue increase and rate design would result in new distribution rates and related distribution revenues ("Rate Case Revenues" or "RCR") for Rider VBA. The Companies proposed the Rider VBA Percentage of Fixed Costs ("PFC") be set at 100%. NS Ex. 15.0 at 12-13, 18; PGL Ex. 15.0 REV. at 12-13, 18.

The Commission agrees that it is necessary under Rider VBA for the Companies to file RCRs and it directs the Companies to do so. The Commission also finds that the PFC should be set at 100%. The Companies' proposals are uncontested and approved.

f. Transportation Riders

i. Transportation Administrative Charges

Based on cost studies, North Shore proposed to increase the Administrative Charge for Riders FST, Full Standby Transportation Service, and SST, Subscription Storage Transportation Service, from $5.74 to $6.14 *per* account and the Pooling Charge for Rider P, Pooling Service, from $1.97 to $2.98 *per* account. NS Ex. 15.0 at 23; NS Ex. 15.9. Peoples Gas proposed to decrease the Riders FST and SST Administrative Charge from $7.78 to $5.82 *per* account and the Rider P Pooling Charge fr**o**m $5.39 to $4.18 *per* account. PGL Ex. 15.0 REV. at 23; PGL Ex. 15.9.

The Commission finds that the Companies' proposed Administrative and Pooling Charges are appropriate and reasonable. The proposals are based on an uncontested cost study. The Commission approves the Companies' proposed Administrative and Pooling Charges.

ii. Rider SBO Credit

The Companies' Rider SBO, Supplier Bill Option Service, allows suppliers providing service to Rider CFY customers to render their own bills to the customers for their services and the Companies' delivery service. The Companies provide a credit to suppliers to compensate them for the Companies' avoided billing cost. Based on a cost study, the Companies proposed to increase the credit from 46 to 47 cents *per* bill *per* month. NS Ex. 15.0 at 23; NS Ex. 15.10; PGL Ex. 15.0 REV. at 23-24; PGL Ex. 15.10.

The Commission finds that the proposed Rider SBO credit is reasonable and based on an uncontested cost study. The Commission approves the proposed Rider SBO credit.

iii. Purchase of Receivables

The Companies observed that Ameren filed for approval of a small volume transportation program, and its proposal includes language to allow utility consolidated billing/purchase of receivables. The Companies witness Ms. Egelhoff stated that the Companies plan to review Ameren's filing and monitor the Commission proceeding.

Based on what the Commission determines for Ameren, they plan to develop and file, in 2015 for 2016 implementation, a purchase of receivables tariff. NS Ex. 15.0 at 24; PGL Ex. 15.0 REV. at 24. The Companies noted that the Commission has not yet issued an Order in the Ameren case, Docket No. 14-0097.

The Commission notes that neither Staff nor intervenors commented on the Companies' proposal. The Commission takes no position on the proposal but will review the merits of any proposed tariff when it is filed.

3. Service Classifications

a. Service Classification Nos. 1 and 2 Terms of Service

The Companies proposed clarifications in the S.C. Nos. 1 and 2 "Terms of Service" language to distinguish more clearly service discontinuance under the Commission's rules (*e.g.*, due to non-payment) from service discontinuance at the customer's request (*e.g.*, when a customer moves). NS Ex. 15.0 at 26; PGL Ex. 15.0 REV. at 26.

The Commission approves the Companies' proposed clarifications to S.C. Nos. 1 and 2. These uncontested proposals are reasonable and are hereby adopted.

X. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) Peoples Gas is an Illinois corporation engaged in the transportation, purchase, storage, distribution and sale of natural gas to the public in Illinois and is a public utility as defined in Section 3-105 of the Act;

(2) North Shore is an Illinois corporation engaged in the transportation, purchase, storage, distribution and sale of natural gas to the public in Illinois and is a public utility as defined in Section 3-105 of the Act;

(3) the Commission has jurisdiction over the parties and the subject matter herein;

(4) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; the Appendices attached hereto provide supporting calculations;

(5) the test year for the determination of the rates herein found to be just and reasonable should be the 12 months ending December 31, 2015; such test year is appropriate for purposes of this proceeding;

(6) the $443,539,000 original cost of plant for North Shore at December 31, 2012, and the $3,285,370,000 original cost of plant for Peoples Gas at December 31, 2012, as presented in Staff Ex.6.0, are unconditionally approved as the original costs of plant;

(7) for the test year ending December 31, 2015, and for the purposes of this proceeding, Peoples Gas' original cost rate base with adjustments is $1,704,364,000;

(8) for the test year ending December 31, 2015, and for the purposes of this proceeding, North Shore's original cost rate base with adjustments is $219,042,000;

(9) a just and reasonable return which Peoples Gas should be allowed to earn on its net original cost rate base is 6.56%; this rate of return incorporates a return on common equity of 9.05% and costs of long-term debt of 4.32% and short-term debt of 0.91%, with a just and reasonable capital structure of 50.33% common equity, 46.51% long-term debt and 3.16% short-term debt;

(10) a just and reasonable return which North Shore should be allowed to earn on its net original cost rate base is 6.26%; this rate of return incorporates a return on common equity of 9.05% and costs of long-term debt of 4.13% and short-term debt of .74%, with a just and reasonable capital structure of 50.48% common equity, 38.94% long-term debt and 10.58% short-term debt;

(11) Peoples Gas' rate of return set forth in Finding (9) results in approved base rate net operating income of $111,806,000;

(12) North Shore's rate of return set forth in Finding (10) results in approved base rate net operating income of $13,708,000;

(13) pursuant to Section 9-229 of the Act, the Commission has specifically assessed the amounts expended by North Shore and Peoples Gas to compensate attorneys and experts to prepare and litigate this general rate case filing and finds those amounts as adjusted in Sections V.B.13, V.C. 3.a.iv, and V.C.4 to be just and reasonable;

(14) Peoples Gas' rates, which are presently in effect, are insufficient to generate the operating income necessary to permit Peoples Gas the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(15) North Shore's rates, which are presently in effect, are insufficient to generate the operating income necessary to permit North Shore the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(16) the specific rates proposed by Peoples Gas in its initial filing do not reflect various determinations made in this Order regarding revenue requirement, expenses, cost of service allocations, and rate design; Peoples Gas'

proposed rates should be permanently canceled and annulled consistent with the findings herein;

(17) the specific rates proposed by North Shore in its initial filing do not reflect various determinations made in this Order regarding revenue requirement, expenses, cost of service allocations, and rate design; North Shore's proposed rates should be permanently canceled and annulled consistent with the findings herein;

(18) Peoples Gas should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $655,025,000, in addition to $16,606,000 of other revenues, which represents a total base rate increase of $74,765,000 or 12.53% in base rate revenues; such revenues will provide Peoples Gas with an opportunity to earn the rate of return set forth in Finding (9) above; based on the record in this proceeding, this return is just and reasonable;

(19) North Shore should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $86,358,000, in addition to $1,597,000 of other revenues, which represents a base rate increase of $ 3,701,000 or 4.45% in base rate revenues; such revenues will provide North Shore with an opportunity to earn the rate of return set forth in Finding (10) above; based on the record in this proceeding, this return is just and reasonable;

(20) it is further ordered that the uncollectible expense included in base rates for People Gas is $13,692,000 and for North Shore is $498,000, which excludes amounts recoverable under Rider UEA-GC;

(21) The test year amounts of test year pipelines safety-related training for Peoples Gas are: $11,355 for Corrosion-NACE Levels 1 and 2 Certification; $80,500 for 49 CFR Parts 191 and 192 Training; $0 for Construction Inspection; $6,300 for all other pipeline safety-related training, totaling $98,135;

(22) the determinations regarding cost of service and rate design contained in the prefatory portion of this Order are reasonable for purposes of this proceeding; the tariffs filed by North Shore and Peoples Gas should incorporate the rates and rate designs set forth and referred to herein, including revisions to their Schedule of Rates for Gas Service;

(23) the percentage of fixed costs for purposes of computations under Rider VBA shall be 100% for each of North Shore and Peoples Gas and North Shore and Peoples Gas shall file revised Rate Case Revenues for Rider VBA;

(24) Peoples Gas shall reflect in its Rider QIP Surcharge Percentage following the date of this Order the variance from the 2014 QIP amounts included in

base rates to its actual 2014 QIP amounts, which may be an increase or decrease to the amount to be recovered through the Rider QIP Surcharge Percentage. The 2014 QIP amounts included in base rates are comprised of $115,986,348, less a negative amount of $33,721,806 for accumulated depreciation and less a positive amount of $8,603,652 for accumulated deferred income taxes, and $1,728,342 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired;

(25) as required in this Order, under the discussion of Rider SSC, Storage Service Charge, North Shore and Peoples Gas shall file Rider SSC charges (Storage Banking Charge and Storage Service Charge) consistent with the approved revenue requirements;

(26) new tariff sheets authorized to be filed by this Order should reflect an effective date consistent with the requirements of Section 9-201(b) as amended; and

(27) North Shore and Peoples Gas' updated depreciation rates are uncontested and they are approved.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets presently in effect of The Peoples Gas Light and Coke Company and North Shore Gas Company that are the subject of this proceeding are hereby permanently canceled and annulled, effective at such time as the new tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general rate increase, filed by The Peoples Gas Light and Coke Company and North Shore Gas Company on February 26, 2014, are permanently canceled and annulled.

IT IS FURTHER ORDERED the $443,539,000 original cost of plant for North Shore at December 31, 2012, and the $3,285,370 original cost of plant for Peoples Gas at December 31, 2012, as presented in Staff Ex. 1.0, are unconditionally approved as the original costs of plant.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company and North Shore Gas Company are authorized to file new tariff sheets with supporting workpapers in accordance with Findings (18) and (19) of this Order, applicable to service furnished on and after the effective date of said tariff sheets, which date shall be no later than four business days after said sheets are filed.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company and North Shore Gas Company shall revise their Schedule of Rates for Gas Service in accordance with Finding 22 of this Order.

IT IS FURTHER ORDERED that the Peoples Gas Light and Coke Company and North Shore Gas Company shall file revised Rider VBA Rate Case Revenue amounts and set the percentage of fixed costs for purposes of computations under Rider VBA at 100%.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company shall reflect in its Rider QIP Surcharge Percentage following the date of this Order the variance from the 2014 QIP amounts included in base rates to its actual 2014 QIP amounts, which may be an increase or decrease to the amount to be recovered through the Rider QIP Surcharge Percentage. The 2014 QIP amounts included in base rates are comprised of $115,986,348, less a negative amount of $33,721,806 for accumulated depreciation and less a positive amount of $8,603,652 for accumulated deferred income taxes, and $1,728,342 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company and North Shore Gas Company shall file Rider SSC charges (Storage Banking Charge and Storage Service Charge) consistent with the approved revenue requirements.

IT IS FURTHER ORDERED that the Utilities' updated depreciation rates are approved.

IT IS FURTHER ORDERED that any motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

Entered this 21st day of January, 2015.

BY ORDER OF THE COMMISSION

Edison Electric Institute

Power by Association℠

Disruptive Challenges:

Financial Implications and Strategic Responses to a Changing Retail Electric Business

Prepared by: Peter Kind
Energy Infrastructure Advocates

Prepared for: Edison Electric Institute

January 2013

Edison Electric Institute

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Executive Summary

Recent technological and economic changes are expected to challenge and transform the electric utility industry. These changes (or "disruptive challenges") arise due to a convergence of factors, including: falling costs of distributed generation and other distributed energy resources (DER); an enhanced focus on development of new DER technologies; increasing customer, regulatory, and political interest in demand-side management technologies (DSM); government programs to incentivize selected technologies; the declining price of natural gas; slowing economic growth trends; and rising electricity prices in certain areas of the country. Taken together, these factors are potential "game changers" to the U.S. electric utility industry, and are likely to dramatically impact customers, employees, investors, and the availability of capital to fund future investment. The timing of such transformative changes is unclear, but with the potential for technological innovation (e.g., solar photovoltaic or PV) becoming economically viable due to this confluence of forces, the industry and its stakeholders must proactively assess the impacts and alternatives available to address disruptive challenges in a timely manner.

This paper considers the financial risks and investor implications related to disruptive challenges, the potential strategic responses to these challenges, and the likely investor expectations to utility plans going forward. There are valuable lessons to be learned from other industries, as well as prior utility sector paradigm shifts, that can assist us in exploring risks and potential strategic responses.

The financial risks created by disruptive challenges include declining utility revenues, increasing costs, and lower profitability potential, particularly over the long-term. As DER and DSM programs continue to capture "market share," for example, utility revenues will be reduced. Adding the higher costs to integrate DER, increasing subsidies for DSM and direct metering of DER will result in the potential for a squeeze on profitability and, thus, credit metrics. While the regulatory process is expected to allow for recovery of lost revenues in future rate cases, tariff structures in most states call for non-DER customers to pay for (or absorb) lost revenues. As DER penetration increases, this is a cost-recovery structure that will lead to political pressure to undo these cross subsidies and may result in utility stranded cost exposure.

While the various disruptive challenges facing the electric utility industry may have different implications, they all create adverse impacts on revenues, as well as on investor returns, and require individual solutions as part of a comprehensive program to address these disruptive trends. Left unaddressed, these financial pressures could have a major impact on realized equity returns, required investor returns, and credit quality. As a result, the future cost and availability of capital for the electric utility industry would be adversely impacted. This would lead to increasing customer rate pressures.

The regulatory paradigm that has supported recovery of utility investment has been in place since the electric utility industry reached a mature state in the first half of the 20th century. Until there is a significant, clear, and present threat to this recovery paradigm, it is likely that the financial markets will not focus on these disruptive challenges, despite the fact that electric utility capital investment is recovered over a period of 30 or more years (i.e., which exposes the industry to stranded cost risks). However, with the current level of lost load nationwide from DER being less than 1 percent, investors are not taking notice of this phenomenon, despite the fact that the pace of change is increasing and will likely increase further as costs of disruptive technologies benefit further from scale efficiencies.

Investors, particularly equity investors, have developed confidence throughout time in a durable industry financial recovery model and, thus, tend to focus on earnings growth potential over a 12- to 24-month period.

So, despite the risks that a rapidly growing level of DER penetration and other disruptive challenges may impose, they are ***not*** currently being discussed by the investment community and factored into the valuation calculus reflected in the capital markets. In fact, electric utility valuations and access to capital today are as strong as we have seen in decades, reflecting the relative safety of utilities in this uncertain economic environment.

In the late 1970s, deregulation started to take hold in two industries that share similar characteristics with the electric utility industry—the airline industry and the telecommunications industry (or “the telephone utility business”). Both industries were price- and franchise-regulated, with large barriers to entry due to regulation and the capital-intensive nature of these businesses. Airline industry changes were driven by regulatory actions (a move to competition), and the telecommunications industry experienced technology changes that encouraged regulators to allow competition. Both industries have experienced significant shifts in the landscape of industry players as a result.

In the airline sector, each of the major U.S. carriers that were in existence prior to deregulation in 1978 faced bankruptcy. The telecommunication businesses of 1978, meanwhile, are not recognizable today, nor are the names of many of the players and the service they once provided (“the plain old telephone service”). Both industries experienced poor financial market results by many of the former incumbent players for their investors (equity and fixed-income) and have sought mergers of necessity to achieve scale economies to respond to competitive dynamics.

The combination of new technologies, increasing costs, and changing customer-usage trends allow us to consider alternative scenarios for how the future of the electric sector may develop. Without fundamental changes to regulatory rules and recovery paradigms, one can speculate as to the adverse impact of disruptive challenges on electric utilities, investors, and access to capital, as well as the resulting impact on customers from a price and service perspective. We have the benefit of lessons learned from other industries to shift the story and move the industry in a direction that will allow for customers, investors, and the U.S. economy to benefit and prosper.

Revising utility tariff structures, particularly in states with potential for high DER adoption, to mitigate (or eliminate) cross subsidies and provide proper customer price signals will support economic implementation of DER while limiting stress on non-DER participants and utility finances. This is a near-term, must-consider action by all policy setting industry stakeholders.

The electric utility sector will benefit from proactive assessment and planning to address disruptive challenges. Thirty year investments need to be made on the basis that they will be recoverable in the future in a timely manner. To the extent that increased risk is incurred, capital deployment and recovery mechanisms need to be adapted accordingly. The paper addresses possible strategic responses to competitive threats in order to protect investors and capital availability. While the paper does not propose new business models for the industry to pursue to address disruptive challenges in order to protect investors and retain access to capital, it does highlight several of the expectations and objectives of investors, which may lead to business model transformation alternatives.

Background

As a result of a confluence of factors (i.e., technological innovation, public policy support for sustainability and efficiency, declining trends in electricity demand growth, rising price pressures to maintain and upgrade the U.S. distribution grid, and enhancement of the generation fleet), the threat of disruptive forces (i.e., new products/markets that replace existing products/markets) impacting the utility industry is increasing and is adding to the effects of other types of disruptive forces like declining sales and end-use efficiency. While we cannot lay out an exact roadmap or timeline for the impact of potential disruptive forces, given the current shift in competitive dynamics, the utility industry and its stakeholders must be prepared to address these challenges in a way that will benefit customers, long-term economic growth, and investors. Recent business history has provided many examples of companies and whole industries that either failed or were slow to respond to disruptive forces and suffered as a result.

Today, a variety of disruptive technologies are emerging that may compete with utility-provided services. Such technologies include solar photovoltaics (PV), battery storage, fuel cells, geothermal energy systems, wind, micro turbines, and electric vehicle (EV) enhanced storage. As the cost curve for these technologies improves, they could directly threaten the centralized utility model. To promote the growth of these technologies in the near-term, policymakers have sought to encourage disruptive competing energy sources through various subsidy programs, such as tax incentives, renewable portfolio standards, and net metering where the pricing structure of utility services allows customers to engage in the use of new technologies, while shifting costs/lost revenues to remaining non-participating customers.

In addition, energy efficiency and DSM programs also promote reduced utility revenues while causing the utility to incur implementation costs. While decoupling recovery mechanisms, for example, may support recovery of lost revenues and costs, under/over recovery charges are typically imposed based on energy usage and, therefore, adversely impact non-participants of these programs. While the financial community is generally quite supportive of decoupling to capture lost revenues, investors have not delved into the long-term business and financial impact of cross subsidization on future customer rates inherent in most decoupling models and the effective recovery thereof. In other words, will non–DER participants continue to subsidize participants or will there be political pressure to not allow cost pass thru over time?

The threat to the centralized utility service model is likely to come from new technologies or customer behavioral changes that reduce load. Any recovery paradigms that force cost of service to be spread over fewer units of sales (i.e., kilowatt-hours or kWh) enhance the ongoing competitive threat of disruptive alternatives. While the cost--recovery challenges of lost load can be partially addressed by revising tariff structures (such as a fixed charge or demand charge service component), there is often significant opposition to these recovery structures in order to encourage the utilization of new technologies and to promote customer behavior change.

But, even if cross-subsidies are removed from rate structures, customers are not precluded from leaving the system entirely if a more cost-competitive alternative is available (e.g., a scenario where efficient energy storage combined with distributed generation could create the ultimate risk to grid viability). While tariff restructuring can be used to mitigate lost revenues, the longer-term threat of fully exiting from the grid (or customers solely using the electric grid for backup purposes) raises the potential for irreparable damages to revenues and growth prospects. This suggests that an old-line industry with 30-year cost recovery of investment is vulnerable to cost-recovery threats from disruptive forces.

Generators in organized, competitive markets are more directly exposed to threats from new technologies and enhanced efficiency programs, both of which reduce electricity use and demand. Reduced energy use and demand translate into lower prices for wholesale power and reduced profitability. With reduced profitability comes less cash flow to invest and to support the needs of generation customers. While every market-driven business is subject to competitive forces, public policy programs that provide for subsidized growth of competing technologies and/or participant economic incentives do not provide a level playing field upon which generators can compete fairly against new entrants. As an example, subsidized demand response programs or state contracted generation additions create threats to the generation owner (who competes based upon free market supply and demand forces).

According to the Solar Electric Power Association (SEPA), there were 200,000 distributed solar customers (aggregating 2,400 megawatts or MW) in the United States as of 2011. Thus, the largest near-term threat to the utility model represents less than 1 percent of the U.S. retail electricity market. Therefore, the current level of activity can be "covered over" without noticeable impact on utilities or their customers. However, at the present time, 70 percent of the distributed activity is concentrated within 10 utilities, which obviously speaks to the increased risk allocated to a small set of companies. As previously stated, due to a confluence of recent factors, the threat to the utility model from disruptive forces is now increasingly viable. One prominent example is in the area of distributed solar PV, where the threats to the centralized utility business model have accelerated due to:

- The decline in the price of PV panels from $3.80/watt in 2008 to $0.86/watt in mid-2012[1]. While some will question the sustainability of cost-curve trends experienced, it is expected that PV panel costs will not increase (or not increase meaningfully) even as the current supply glut is resolved. As a result, the all-in cost of PV solar installation approximates $5/watt, with expectations of the cost declining further as scale is realized;
- An increase in utility rates such that the competitive price opportunity for PV solar is now "in the market" for approximately 16 percent of the U.S. retail electricity market where rates are at or above $0.15/kWh[2]. In addition, projections by PV industry participants suggest that the "in the money" market size will double the share of contestable revenue by 2017 (to 33 percent, or $170 billion of annual utility revenue);
- Tax incentives that promote specific renewable resources, including the 30-percent Investment Tax Credit (ITC) that is effective through 2016 and five-year accelerated depreciation recovery of net asset costs;
- Public policies to encourage renewable resource development through Renewable Portfolio Standards (RPS), which are in place in 29 states and the District of Columbia and which call for renewable generation goals within a state's energy mix;
- Public policies to encourage net metering, which are in effect in 43 states and the District of Columbia (3 additional states have utilities with voluntary net metering programs) and which typically allow customers to sell excess energy generated back to the utility at a price greater than the avoided variable cost[3];
- Time-of-use rates, structured for higher electric rates during daylight hours, that create incentives for installing distributed solar PV, thereby taking advantage of solar benefit (vs. time-of-use peak rates) and net metering subsidies; and

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1 Source: Bloomberg New Energy Finance, *Solar Module Price Index*
2 Source: Energy Information Agency, *Electricity Data Overview*
3 Source: Database for State Incentives for Renewables and Efficiency, www.dsireusa.org

- The evolution of capital markets' access to businesses that leverage the dynamics outlined above to support a for-profit business model. Examples include tax equity financing, project finance lending, residential PV leasing models (i.e., "no money down" for customers), and public equity markets for pure play renewable resource providers and owners. As an illustration, U.S. tax equity investment is running at $7.5 billion annualized for 2012.[4] Add other sources of capital, including traditional equity, and this suggests the potential to fund a large and growing industry.

Bloomberg New Energy Finance (BNEF) projects that distributed solar capacity will grow rapidly as a result of the competitive dynamics highlighted. BNEF projects 22-percent compound annual growth in PV installations through 2020, resulting in 30 gigawatts (GW) of capacity overall (and approximately 4.5 GW coming from distributed PV). This would account for 10 percent of capacity in key markets coming from distributed resources and even a larger share of year-round energy generated.

Assuming a decline in load, and possibly customers served, of 10 percent due to DER with full subsidization of DER participants, the average impact on base electricity prices for non-DER participants will be a 20 percent or more increase in rates, and the ongoing rate of growth in electricity prices will double for non-DER participants (before accounting for the impact of the increased cost of serving distributed resources). The fundamental drivers previously highlighted could suggest even further erosion of utility market share if public policy is not addressed to normalize this competitive threat.

While the immediate threat from solar PV is location dependent, if the cost curve of PV continues to bend and electricity rates continue to increase, it will open up the opportunity for PV to viably expand into more regions of the country. According to ThinkEquity, a boutique investment bank, as the installed cost of PV declines from $5/watt to $3.5/watt (a 30-percent decline), the targeted addressable market increases by 500 percent, including 18 states and 20 million homes, and customer demand for PV increases by 14 times. If PV system costs decline even further, the market opportunity grows exponentially. In addition, other DER technologies being developed may also pose additional viable alternatives to the centralized utility model.

Due to the variable nature of renewable DER, there is a perception that customers will always need to remain on the grid. While we would expect customers to remain on the grid until a fully viable and economic distributed non-variable resource is available, one can imagine a day when battery storage technology or micro turbines could allow customers to be electric grid independent. To put this into perspective, who would have believed 10 years ago that traditional wire line telephone customers could economically "cut the cord?"

The cost of providing interconnection and back-up supply for variable resources will add to the utility cost burden. If not properly addressed in the tariff structure, the provision of these services will create additional lost revenues and will further challenge non-DER participants in terms of being allocated costs incurred to serve others.

Another outcome of the trend of rising electricity prices is the potential growth in the market for energy efficiency solutions. Combining electricity price trends, customer sustainability objectives, and ratemaking incentives via cross-subsidies, it is estimated that spending on energy efficiency programs will increase by as much as 300 percent from 2010 to 2025, within a projected range of $6 to $16 billion per year[5]. This level of

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[4] Source: Bloomberg New Energy Finance, *Renewable Energy-Research Note*, July 18, 2012
[5] Source: Lawrence Berkeley National Laboratory, *The Future of Utility Funded Energy Efficiency Programs in the United States: Projected Spending and Savings 2010 to 2025*, January 2013

spending on energy efficiency services will have a meaningful impact on utility load and, thus, will create significant additional lost revenue exposure.

The financial implications of these threats are fairly evident. Start with the increased cost of supporting a network capable of managing and integrating distributed generation sources. Next, under most rate structures, add the decline in revenues attributed to revenues lost from sales foregone. These forces lead to increased revenues required from remaining customers (unless fixed costs are recovered through a service charge tariff structure) and sought through rate increases. The result of higher electricity prices and competitive threats will encourage a higher rate of DER additions, or will promote greater use of efficiency or demand-side solutions.

Increased uncertainty and risk will not be welcomed by investors, who will seek a higher return on investment and force defensive-minded investors to reduce exposure to the sector. These competitive and financial risks would likely erode credit quality. The decline in credit quality will lead to a higher cost of capital, putting further pressure on customer rates. Ultimately, capital availability will be reduced, and this will affect future investment plans. The cycle of decline has been previously witnessed in technology-disrupted sectors (such as telecommunications) and other deregulated industries (airlines).

Disruptive Threats—Strategic Considerations

A disruptive innovation is defined as "an innovation that helps create a new market and value network, and eventually goes on to disrupt an existing market and value network (over a few years or decades), displacing an earlier technology. The term is used in business and technology literature to describe innovations that improve a product or service in ways that the market does not expect, typically first by designing for a different set of consumers in the new market and later by lowering prices in the existing market."

Disruptive forces, if not actively addressed, threaten the viability of old-line exposed industries. Examples of once-dominant, blue chip companies/entities being threatened or succumbing to new entrants due to innovation include Kodak and the U.S. Postal Service (USPS). For years, Kodak owned the film and related supplies market. The company watched as the photo business was transformed by digital technology and finally filed for bankruptcy in 2012.

Meanwhile, the USPS is a monopoly, government-run agency with a mission of delivering mail and providing an essential service to keep the economy moving. The USPS has been threatened for decades by private package delivery services (e.g., UPS and FedEx) that compete to offer more efficient and flexible service. Today, the primary threat to USPS' viability is the delivery of information by email, including commercial correspondence such as bills and bill payments, bank and brokerage statements, etc. Many experts believe that the USPS must dramatically restructure its operations and costs to have a chance to protect its viability as an independent agency.

Participants in all industries must prepare for and develop plans to address disruptive threats, including plans to replace their own technology with more innovative, more valuable customer services offered at competitive prices. The traditional wire line telephone players, including AT&T and Verizon, for example, became leaders in U.S. wireless telephone services, which over time could make the old line telephone product extinct. But these innovative, former old-line telephone providers had the vision to get in front of the trend to wireless and lead the development of non-regulated infrastructure networks and consumer marketing skills. As a result, they now hold large domestic market shares. In fact, they have now further leveraged technology innovation to create new products that expand their customer offerings.

The electric utility sector has not previously experienced a viable disruptive threat to its service offering due customer reliance and the solid economic value of its product. However, a combination of technological innovation, public/regulatory policy, and changes in consumer objectives and preferences has resulted in distributed generation and other DER being on a path to becoming a viable alternative to the electric utility model. While investors are eager to support innovation and economic progress, they do not support the use of subsidies to attack the financial viability of their invested capital. Utility investors may not be opposed to DER technologies, but, in order for utilities to maintain their access to capital, it is essential that the financial implications of DER technologies be addressed so that non-DER participants and investors are not left to pay for revenues lost (and costs unrecovered) from DER participants.

Finance 101 - Introduction to Corporate Finance

Investors allocate investment capital to achieve their financial objectives consistent with their tolerance for risk and time horizon. Fixed-income (i.e., bond) investors seek certainty as to (investment) returns through a guarantee by the debt issuer of timely payment of principal and interest. Equity investors seek a higher expected return than debt investors and, accordingly, must accept increased risk. “Expected” return refers to the distinction that equity investor returns are not guaranteed; therefore, equity investors bear a higher level of risk than bondholders. The expected return on equity investment is realized through a combination of dividends received and expected growth in value per share (which is achieved through a combination of growth in earnings and dividends and/or a rerating of return expectations as a result of investment market forces).

Corporate financial objectives focus on enhancing shareholder value through achieving long-term growth consistent with the preservation of the corporate entity. Corporations develop financial policies to support the access to capital to achieve their business plans. For utilities, these financial policies are consistent with investment-grade credit ratings. Since practically all utilities have an ongoing need for capital to fund their capital expenditure programs, the industry has developed financial policies intended to support the access to relatively low-cost capital in (practically) all market environments. Under traditional cost-of-service ratemaking, customers benefit through lower cost of service and, therefore, lower rates.

In order to retain the financial flexibility required to maintain investment-grade credit ratings, the rating agencies prefer policies that promote the retention of corporate cash flow and provide a liquidity cushion to support fixed obligations. Prudent corporate financial management disdains significant fixed commitments to investors—since such commitments limit management flexibility and increase capital-access dependency and risk. While paying dividends to equity investors is not a legal obligation, the rating agencies and investors view dividends as a moral (or intended) obligation that management will not reduce unless it has no viable alternative to preserve long-term corporate value. The corporate financial objective of retaining cash from operations to support credit quality limits the potential to pay dividends to investors. Thus, growth of investment value is required by equity investors (as discussed above) to achieve return expectations warranted by the increased risk taken and investment return expectations relative to fixed income investors.

It is important to highlight that the rating agencies’ rating criteria and associated target corporate credit metrics reflect the credit risk of the industry environment of the corporation being rated. Thus, due to the benefits of a stable regulatory environment, utilities are able to maintain (for a given rating category) significantly more debt relative to cash flow than competitive industries. However, if business risks were to increase for utilities in the future, as we will discuss in the next sections, it would be likely that utility debt leverage (i.e., debt relative to cash flow) would need to be reduced in order to retain credit ratings.

Stable, mature industries—those that have a proven product, stable product demand, and low volatility related to their revenues and cash flow (the “defensive industries”)—are attractive to investors as they offer more certainty and fewer business and financial risks. As a result, investors in these stable, defensive industries (such as utilities) will require a lower expected return compared to investors in less mature and more volatile industries. We describe this lower expected return requirement as a lower cost of capital. This lower cost of capital associated with defensive industries is manifested in lower borrowing costs and higher relative share values. In addition, in difficult financial market environments (such as we experienced in October 2008 through March 2009), these stable businesses typically experience less adverse stock price impact due to investors fleeing in order to reduce risk. Thus, in difficult markets, mature companies have demonstrated ongoing financial market access (investor demand) when those in other industries have not. This is the benefit (or the “insurance policy”) of an investment-grade credit rating—lower capital costs and more stable access to capital despite market conditions.

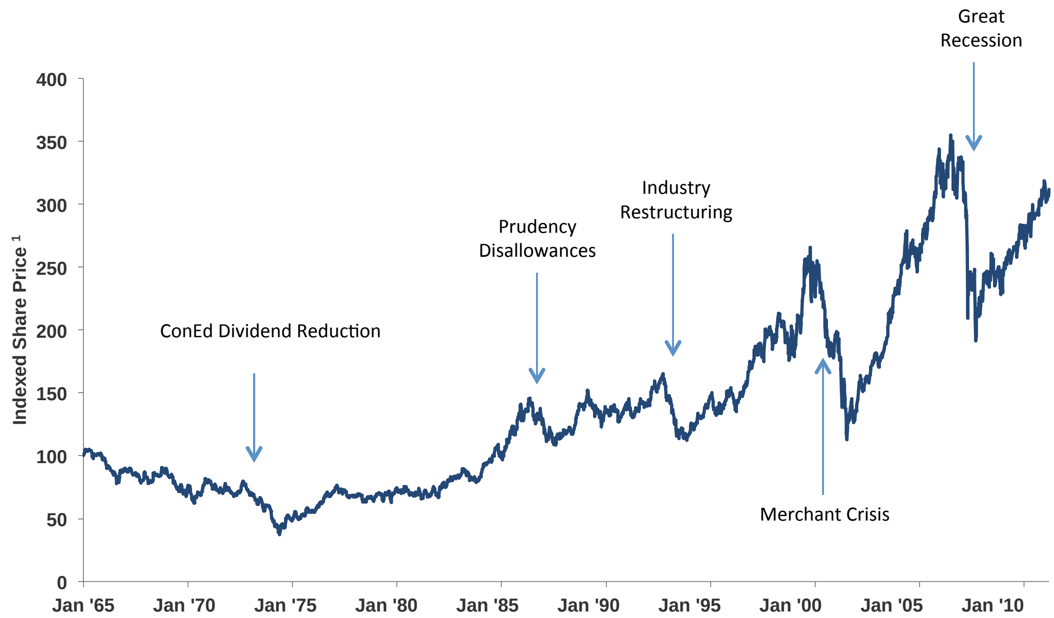
The benefit to customers of cost-of-service rate-regulated utilities is that a lower cost of capital contributes to lower utility rates. Also of importance, but often taken for granted, is the comfort that comes with knowing that utilities will have capital access to support the reliability and growth needs of their service territories and, thus, will not adversely expose customer service needs, including customer growth plans.

Finance 201 - Financial Market Realities

With the exception of a very few periods over the past century, utilities have experienced unfettered access to relatively low-cost capital. Even during challenging financial market environments when many industries have been effectively frozen from capital access, utilities have been able to raise capital to support their business plans. The primary reason for the markets’ willingness to provide capital to the utility sector is the confidence that investors place in the regulatory model, particularly the premise that utilities will be awarded the opportunity to earn a fair return on investor capital investment.

However, at times of regulatory model uncertainty, we have seen the financial markets punish utility securities. Examples of periods of investor uncertainty would include the timeframe post the 1973 oil embargo, which was prior to the enactment of fuel adjustment clauses for purchased power; the nuclear power plant abandonments and cost disallowances of the 1980s that led to multiple bankruptcies and financial distress for quite a few utilities; the PURPA cost fallout of the 1990s; and the post-Enron bankruptcy collapse of the merchant power sector in the early 2000s, which challenged merchant energy providers and heavily exposed utility counterparties. These events led to bankruptcies, longstanding financial distress for impacted utilities, and ongoing erosion in credit quality and investor confidence. These examples highlight that regulated businesses are vulnerable to risks related to business model changes, economic trends and regulatory policy changes. When investors focus on these issues as being material risks, the impact on investors and capital formation can be significant.

Exhibit 1
Dow Jones Utility Index: 1965-2012



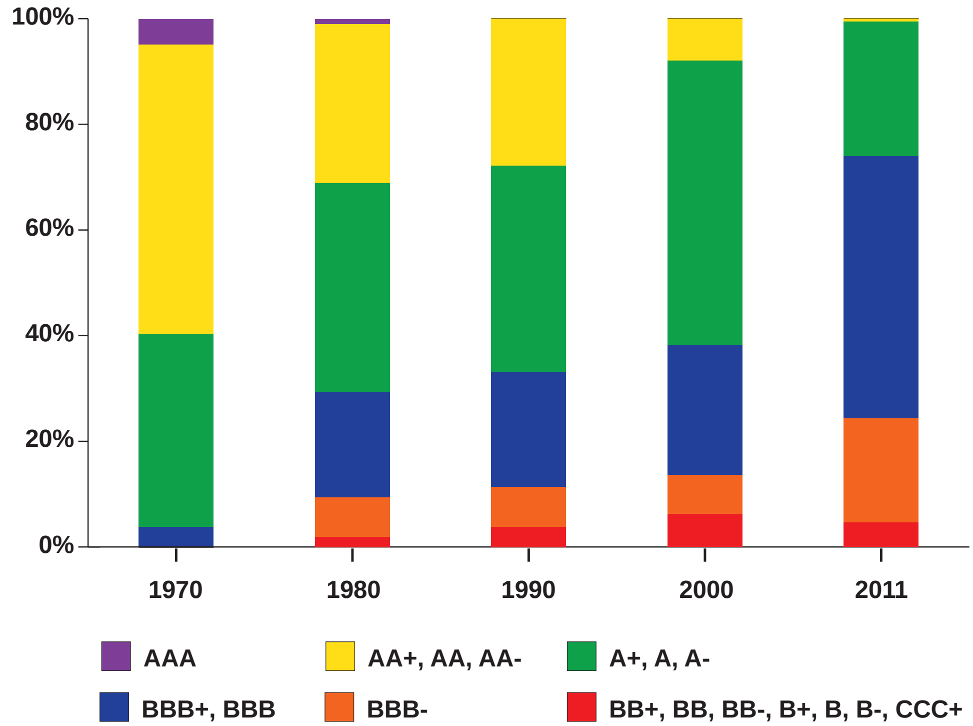
(1) Indexed to 1/2/1970 price

Source: Bloomberg

Prior to the 1980s, the utility sector was dominated by "AA" credit ratings. Power supply-side cost pressures, declining economic and customer growth trends, inflation in cost-of-service provision, and an evolving industry and regulatory model have resulted in steady erosion in credit quality over each of the last five decades. (See Exhibit 2 for a credit-rating history of the electric utility sector.) Investors responded to these periods of significant industry challenge with a rethink of their "blind" faith in the regulatory model and became more focused on company selection as they approached investment strategy. But, for the most part, as utilities and regulation adjusted to political, regulatory, and economic challenges, investor faith in the regulatory model has been restored.

After five decades of decline in industry credit quality, a potential significant concern now is that new competitive forces, which have not been a concern of investors to date, will lead to further credit erosion. The industry cannot afford to endure significant credit quality erosion from current ratings levels without threatening the BBB ratings that are held by the majority of the industry today. Non-investment grade ratings would lead to a significant rerating of capital costs, credit availability, and investor receptivity to the sector. The impact on customers would be dramatic in terms of increased revenue requirements (i.e., the level of revenues required for a utility to cover its operating costs and earn its allowed cost of capital), customer rates, and reduction in the availability of low-cost capital to enhance the system.

Exhibit 2
Electric utility industry credit ratings distribution evolution
(S&P Credit Ratings Distribution, U.S. Shareholder-Owned Electric Utilities)



Source: Standard & Poor's, Macquarie Capital

As we look at the electric utility sector today, investors, for the most part, remain confident that the regulatory model will be applied fairly to provide them with the opportunity to earn a reasonable and fair return on their investment. Those states that have experienced prior upheavals in their regulatory model (e.g., California) have had to tighten their approach to regulatory cost recovery to convince investors that past problems have been addressed. If a state has not been as receptive to addressing its approach to past problems, then investors will be highly reticent to deploy capital in those jurisdictions.

In reviewing recent sector research reports, the majority of security analysts continue to project future earnings levels based on assumed capital-investment levels and projected costs of capital (a bottoms-up approach). While analysts acknowledge that each rate case carries some degree of uncertainty, there appears to be limited focus in their analysis on service area quality, competitiveness of customer pricing, and the drivers for future service territory growth. No other significant industry is analyzed by Wall Street on a bottoms-up basis; the basis for analysis of non-utility industries is competitive position, sales prospects, and sales margins. In addition, the threat of disruptive forces is given no (or almost no) printed lines in utility sector research. This approach to investment analysis is based upon confidence in utilities' ability to earn a fair return on prudent investment. But, it may expose investors to the future economic risks posed by rapid growth in DER. What will happen as technological advancement in the utility sector provides customers with viable competitive alternatives?

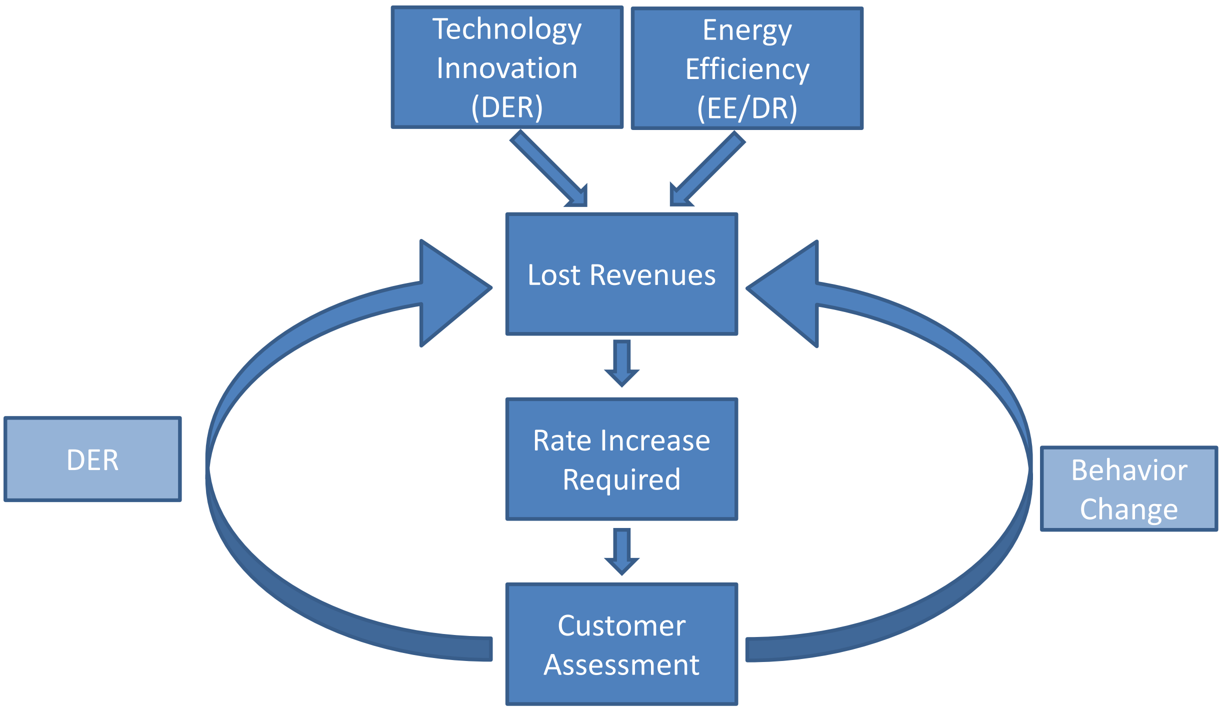
Finance 501 - Financial Implications of Disruptive Forces

As discussed previously, equity investors expect and will value an equity security based upon growth attributes as a major component of the expected total return investors require. Growth in utility earnings has historically been realized by a combination of increased electricity sales (volume), increased price per unit of sales (higher rates), and/or expanded profit margins on incremental revenues achieved between rate cases reflecting the realization of operational/overhead efficiencies. Earnings levels and growth are also impacted by changing costs of capital due to market forces—this is currently a depressant on utility earnings per share (EPS) levels due to the sector-wide decline in authorized returns on equity (ROE) realized over the last several years.

First, let’s review the current climate for the utility sector. While valuations are near all-time highs, the headwinds facing the sector are significant. Concerns start with the anemic electricity demand, which has been primarily impacted by the overall economic climate but also impacted by demand-side efficiency programs and the emergence of DER. Next, there is the need to deploy capital investment at almost twice the rate of depreciation to enhance the grid and address various regulatory mandates. Soft electricity demand plus increasing capital investment lead to rate increase needs and the investment uncertainty created by a future active rate case calendar. While sell side analysts are expecting EPS growth of 4 percent to7 percent overall for the regulated sector, this is likely to be quite challenging. If investor expectations are not realized, a wholesale reevaluation of the sector is likely to occur.

So, what will happen when electricity sales growth declines and that decline is not cyclical but driven by disruptive forces, including new technology and/or the further implementation of public policy focused on DSM and DER initiatives? In a cost-of-service rate-regulated model, revenues are not directly correlated to customer levels or sales but to the cost of providing service. However, in most jurisdictions, customer rates are a function of usage/unit sales. In such a model, customer rate levels must increase via rate increase requests when usage declines, which from a financial perspective is intended to keep the company whole (i.e., earn its cost of capital). However, this may lead to a challenging cycle since an increase in customer rates over time to support investment spending in a declining sales environment (due to disruptive forces) will further enhance the competitive dynamics of competing technologies and supply/demand efficiency programs. This set of dynamics can become a vicious cycle (See Exhibit 3) that, in the worst-case scenario, would leave few(er) customers remaining to support the costs of a large embedded infrastructure system, some of which may be stranded investment but most of the costs will continue to be incurred in order to manage the flows between supply and customers.

Exhibit 3
Vicious Cycle from Disruptive Forces



When investors realize that a business model has been stung by systemic disruptive forces, they likely will retreat. When is the typical tipping point when investors realize that the merits of the investment they are evaluating or monitoring has been forever changed? Despite all the talk about investors assessing the future in their investment evaluations, it is often not until revenue declines are reported that investors realize that the viability of the business is in question.

An interesting example is the story of RIM, the manufacturer of the Blackberry handheld information management tool. From its public start in the 1990s thru 2008, RIM was a Wall Street darling. Its share price was less than $3 in 1999 and peaked at $150 in 2008. The company started to show a stall in sales in 2011, and, now, despite a large cash position and 90 million subscribers, the market is questioning RIM's ability to survive and RIM's stock has plummeted from its high.

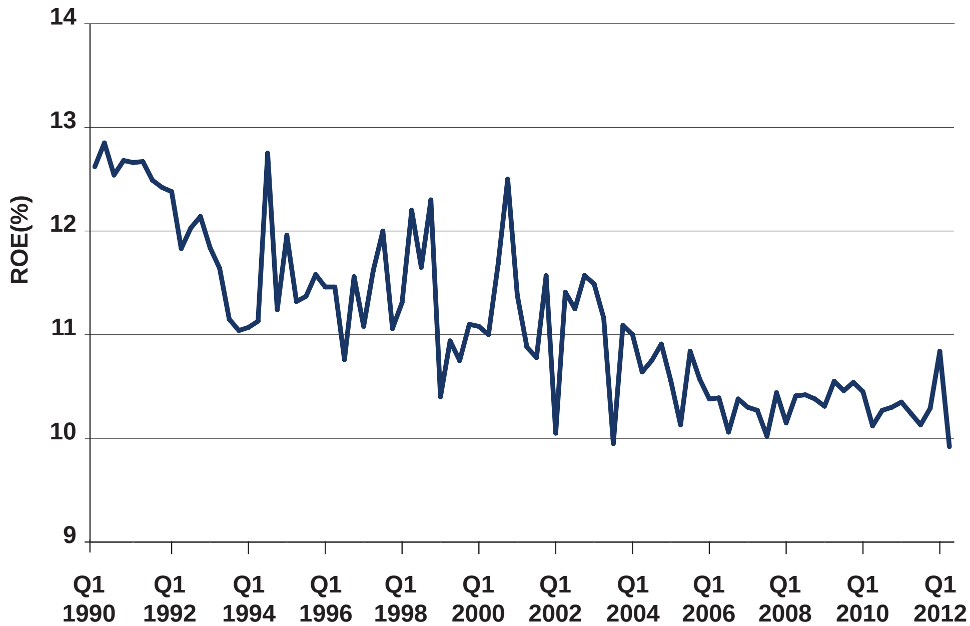
What happened to this powerful growth company that had dominant market shares in a growth market? The answer is the evolution of the iPhone, which transformed the handheld from an email machine to a dynamic Internet tool with seemingly unlimited applications/functionality. When the iPhone was first released in 2007, it was viewed as a threat to RIM, but RIM continued to grow its position until the introduction of the iPhone 4 in June 2010. The iPhone 4, which offered significant improvements from prior versions, led to a retreat in RIM's business and caused a significant drop in its stock price.

It seems that investors have proven to be reasonably optimistic on selected industries even though the competitive threat is staring them head-on. However, if we can identify actionable disruptive forces to a business or industry, then history tells us that management and investors need to take these threats seriously and not wait until the decline in sales and revenues has commenced to develop a new strategy or, in the case of investors, realize their loss.

As discussed above, investors in the utility sector seek increased certainty (or less risk) than in other industries and have confidence in the consistent application of ratemaking recovery models to provide a lower degree of investment risk. As a result of this confidence, when instances have occurred in the past that have not provided consistent application of expected cost recovery models, investors have responded and have caused significant adverse impact on entities' ability to raise incremental capital. But, with the exception of the California energy crisis in the early 2000s, these events reflected embedded cost issues that had defined exposures and time frames. Disruptive changes are a new type of threat to the electric utility industry. Disruptive changes lead to declining customer and usage per customer levels that cannot be easily quantified as to the potential threat posed to corporate profitability. This type of problem has not been faced before by the electric industry and, thus, must be understood as to the strategic issues and alternatives that are raised.

The new potential risk to utility investors from disruptive forces is the impact on future earnings growth expectations. Lost revenues within a net metering paradigm, for instance, are able to be recovered in future rate cases. However, without a shift in tariff structures, there is only so much of an increase that can be placed on remaining non-DER customers before political pressure is brought to bear on recovery mechanisms. Once the sustainability of the utility earnings model is questioned, investors will look at the industry through a new lens, and the view from this lens will be adverse to all stakeholders, including investors and customers. While we do not know the degree to which customer participation in DER and behavior change will impact utility earnings growth, the potential impact, based upon DER trends, is considerable (as stated earlier, industry projections propose that 33 percent of the market will be in the money for DER by 2017, assuming current tax and regulatory policies). Today, regulated utilities have seen allowed returns on equity decline to around 10 percent, a multi-decade low point, as a result of declining interest rates (See Exhibit 4). The cost of equity has also been growing. However, the risks in the business have never been higher, due to increasing customer rate pressures from capital expenditures required to upgrade the grid and address environmental mandates, inflation, low/negative demand growth from active customers, and the threat of load lost due to the rapid development of DER and disruptive forces. The impact of declining allowed returns and increasing business risk will place pressure on the quality and value of utility investments. How large of an impact on investment value will be a function of the impact of disruptive forces described herein. But, lower stock prices will likely translate into lower levels of capital spend, lower domestic economic growth, and fewer grid enhancements.

Exhibit 4
History of Allowed ROE's (U.S. Shareholder-Owned Electric Utilities)
(Based on regulatory cases **settled** each quarter)



Source: SNL Financial/Regulatory Research Associates (RRA), EEI Rate Department

Telephone Industry Parallels

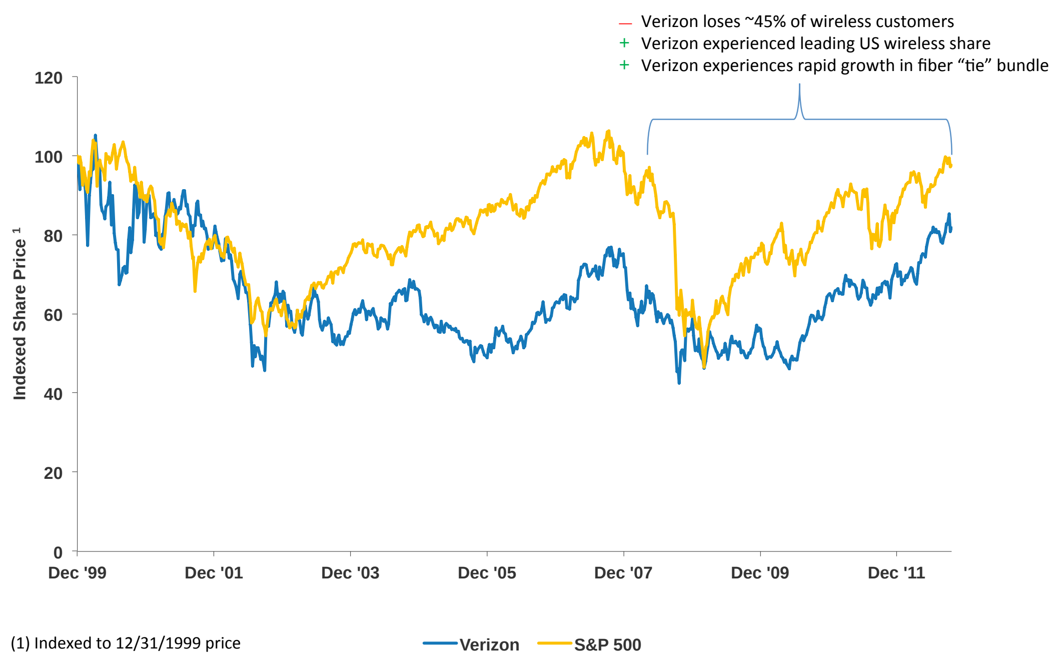
There are other examples in other industries that can provide lessons as to the risks of disruptive change confronting the U.S. electric utility industry. The once fully regulated, monopoly telephone industry provides one clear example. The telephone industry experienced significant technological changes that led to deregulation—initially in the long-distance sector and then followed by the local exchange market.

Beginning in the 1970s, the impact of an array of new technologies (e.g., satellite, microwave, and fiber optic technologies) led to increased telephone system capacity and a reduction in the cost of providing telephone service. These technological changes provided the opportunity for competition by new entrants using newer technologies, while the monopoly service provided by AT&T used older analog technology. In 1974, MCI, a new entrant, filed an anti-trust case challenging AT&T's monopoly powers in long-distance telephone service. The U.S. government ruled against AT&T in 1982, which led to a negotiated plan to break up the Bell system, which was completed in 1984. As a result, long-distance telephone service and the Bell Labs' research arms were housed in AT&T. The local provision of phone service (i.e., intrastate regional calls) was to remain regulated and was to be provided by seven Bell Operating Companies ("the Baby Bells"). By 1996, the Telecommunications Act opened the local telephone market to competition and allowed for Internet providers to acquire spectrum services.

Dramatic technological change has evolved over the past 35 years, which has led to the development of a new infrastructure system; new services that are providing abundant transfer of information; and the convergence of voice, data, and entertainment into one combined service from what had previously been viewed as separate and distinct services and industries. Today, the number of customers who utilize the previously exclusive "copper wire "telephone system represents a rapidly declining percentage of the market for telephone services. (Verizon Communications, for example, has lost approximately 45 percent of its wire line customers over the past five years.) Today, many customers access voice services exclusively through mobile cellular (wireless) phones, a technology that became commercially viable in the mid- to late-1980s. In addition, the advent of cable-based phone service has sped the decline in copper-based services.

This transformation in the telephone sector of pre-1982 to today has not been smooth or easy. Significant capital investment has been made to develop new technologies and related infrastructure—it is estimated of that more than $300 billion has been deployed to build out new telephone infrastructure. New entrants have experienced booms and busts as the supply of capacity outstripped demand, leading to bankruptcies and mergers. The original AT&T, the seven Baby Bells, and several large independent monopolies (e.g., GTE, Citizens, United Telephone and Alltel) have merged into four independent companies. The sector today is dominated by wireless and cable-based technologies.

Exhibit 5
Verizon Stock Price vs. S&P500 from 2000 to 2012



Source: FactSet

There are important lessons to be learned from the history of the telephone industry. First, at the onset of the restructuring of the Bell System, there was no vision that the changes to come would be so radical in terms of the services to be provided and the technologies to be deployed. Second, the telephone players acted boldly to consolidate to gain scale and then take action to utilize their market position to expand into new services on a national scale. Finally, and most important, if telephone providers had not pursued new technologies and the transformation of their business model, they would not have been able to survive as viable businesses today. So, while the sector has underperformed the overall market since 2000, and as shown in Exhibit 5, even a leading industry participant like Verizon Communications has not been able to perform in-line with the overall market despite its growth, market share and solid profitability outlook due to the competitive uncertainties inherent in the business. However, those telecom providers that have embraced new technologies and addressed the competitive threats they faced have managed to survive and to protect investors from a "Kodak moment."

Exhibit 6
Credit Capacity of Regulated vs. Competitive Industries

Sector/Segment	Enterprise Value ($bn)	Credit Ratings		Credit Quality Metrics	
		Moody's	S&P	FFO/Debt	Debt/EBITDA
Regulated Utilities					
Southern Company	$63	Baa1	A	25%	3.5x
ConEd	27	Baa1	A-	25%	3.3x
Xcel Energy	24	Baa1	A-	23%	3.8x
Hybrid Utilities					
Exelon Corp	48	Baa2	BBB	55%	3.1x
PSEG Resources	23	Baa2	BBB	38%	2.3x
Telephone					
AT&T	266	A2	A-	54%	2.1x
Verizon Communications	222	A3	A-	63%	1.9x

	DDM COE (1)	Debt / EBITDA	Implied Debt / Capital	Pre-Tax WACC
Regulated Entity	10%	3.5	50%	10.20%
Competitive Telco	12%	2	34%	13.80%
Competitive Sector Cost Premium				3.60%
% Change in WACC				35.00%

(1) "DDM COE" is dividend discount model cost of equity

From being led by a "AAA" rated company with monopoly powers (AT&T), the telecommunications industry looks very different today. Services today are often comprised of a bundle of telephone, Internet, and entertainment options provided on an unlimited basis by a monthly fee (relative to usage-based pricing prior to 1982). The market has seen significant new entrants, capital investment, and boom and bust periods leading to bankruptcies and/or mergers to enhance scale. Due to the increased competitive business risk, the credit-rating agencies have downgraded the credit rating of AT&T from "AAA" in 1981 to "A "today. In addition, due to competitive business dynamics, the credit rating agencies expect to see significantly lower debt leverage (thereby, raising the overall cost of capital) in order to support the credit ratings assigned. To compare with the electric sector, a comparable rating in telecom would bear approximately 50 percent of the leverage level of a regulated electric utility—resulting in an approximately 35 percent higher pre-tax weighted cost of capital for the telephone sector based on credit-ratings metrics (See Exhibit 6).

While customers have benefitted from a proliferation of new services provided at a lower cost, investors have not done as well in financing a transition to a competitive industry. These lessons should be fully considered as stakeholders shape the approach electric utilities pursue in participating in an environment where disruptive technologies may transform the provision of services and the providers of these new services.

One significant difference between the electric sector and the telecom restructuring example is the value of the respective infrastructure following the disruptive threat. In the telecom situation, the original copper wire phone network is of no/low value in a wireless, Internet protocol, landline world. However, the value of the electric grid to the customer is retained in a distributed generation environment as the grid provides the highway to sell power generated by the DER and the back-up resource infrastructure to deliver power required when the DER is not meeting the load obligation of its provider. In essence, while a wireless user does not need a landline, an electric consumer-generator will not be able to and will not necessarily want to achieve full independence from the “wired” utility grid. So, while the telecom example is a tale of responding to the threat of obsolescence, the near-term challenge to the electric sector is providing the proper tariff design to allow for equitable recovery of revenue requirements to address the pace of non-economic sector disruption.

Strategic Implications of Distribution 2020 Disruptive Forces

The threats posed to the electric utility industry from disruptive forces, particularly distributed resources, have serious long-term implications for the traditional electric utility business model and investor opportunities. While the potential for significant immediate business impact is currently low (due to low DER participation to date), the industry and its stakeholders must begin to seriously address these challenges in order to mitigate the potential impact of disruptive forces, given the prospects for significant DER participation in the future.

One example of a significant potential adverse impact to utility investors stems from net metering. Utilities have witnessed the implementation of net metering rules in all but a handful of states. Lost revenues from DER are being recovered from non-DER customers in order to encourage distributed generation implementation. This type of lost revenue recovery drives up the prices of those non-participating customers and creates the environment for ongoing loss of additional customers as the system cost is transferred to a smaller and smaller base of remaining customers.

Utility investors are not being compensated for the risks associated with customer losses resulting from increasing DER. It is difficult to identify a rate case in which the cost-of-capital implications of net metering were considered. At the point when utility investors become focused on these new risks and start to witness significant customer and earnings erosion trends, they will respond to these challenges. But, by then, it may be too late to repair the utility business model.

DER is not the only disruptive risk the industry faces. Energy efficiency and DSM programs that promote lower electricity sales pressure earnings required to support capital investment. Without a tariff structure that properly allocates fixed vs. variable costs, any structure for lost revenues would come at a cost to non-participating customers, who will then be more motivated to find alternatives to reduce their consumption. While it is not the objective of this paper to outline new business model alternatives to address disruptive challenges, there are a number of actions that utilities and stakeholders should consider on a timely basis to align the interests of all stakeholders, while avoiding additional subsidies for non-participating customers.

These actions include:

Immediate Actions:

- Institute a monthly customer service charge to all tariffs in all states in order to recover fixed costs and eliminate the cross-subsidy biases that are created by distributed resources and net metering, energy efficiency, and demand-side resources;
- Develop a tariff structure to reflect the cost of service and value provided to DER customers, being off-peak service, back-up interruptible service, and the pathway to sell DER resources to the utility or other energy supply providers; and
- Analyze revision of net metering programs in all states so that self-generated DER sales to utilities are treated as supply-side purchases at a market-derived price. From a load provider's perspective, this would support the adoption of distributed resources on economically driven bases, as opposed to being incentivized by cross subsidies.

Longer-term Actions:

- Assess appropriateness of depreciation recovery lives based on the economic useful life of the investment, factoring the potential for disruptive loss of customers;
- Consider a stranded cost charge in all states to be paid by DER and fully departing customers to recognize the portion of investment deemed stranded as customers depart;
- Consider a customer advance in aid of construction in all states to recover upfront the cost of adding new customers and, thus, mitigate future stranded cost risk;
- Apply more stringent capital expenditure evaluation tools to factor-in potential investment that may be subject to stranded cost risk, including the potential to recover such investment through a customer hook-up charge or over a shorter depreciable life;
- Identify new business models and services that can be provided by electric utilities in all states to customers in order to recover lost margin while providing a valuable customer service—this was a key factor in the survival of the incumbent telephone players post deregulation; and
- Factor the threat of disruptive forces in the requested cost of capital being sought.

Investors have no desire to sit by and watch as disruptive forces slice away at the value and financial prospects of their investment. While the utility sector provides an important public good for customers, utilities and financial managers of investments have a fiduciary responsibility to protect the value of invested capital. Prompt action to mitigate lost revenue, while protecting customers from cross-subsidization better aligns the interests of customers and investors.

As growth in earnings and value is a major component of equity investment returns, what will investors expect to see as a strategic response from the industry to disruptive forces? The way to realize growth in earnings is to develop profit streams to counterbalance the impact of disruptive forces. Examples of new profit sources would include ownership of distributed resources with the receipt of an ongoing service fee or rate basing the investment and financial incentives for utilities to encourage demand side/energy efficiency benefits for customers. From an investor perspective, this may be easier said than done because the history of the electric utility industry in achieving non-regulated profits/value creation streams has not been a pleasant experience. So, investors will want to see very clear cut programs to capture value that are consistent with the core strengths of utilities: ability to execute construction projects, to provide dependable service with high reliability, and to access relatively low-cost capital.

Summary

While the threat of disruptive forces on the utility industry has been limited to date, economic fundamentals and public policies in place are likely to encourage significant future disruption to the utility business model. Technology innovation and rate structures that encourage cross subsidization of DER and/or behavioral modification by customers must be addressed quickly to mitigate further damage to the utility franchise and to better align interests of all stakeholders.

Utility investors seek a return on investment that depends on the increase in the value of their investment through growth in earnings and dividends. When customers have the opportunity to reduce their use of a product or find another provider of such service, utility earnings growth is threatened. As this threat to growth becomes more evident, investors will become less attracted to investments in the utility sector. This will be manifested via a higher cost of capital and less capital available to be allocated to the sector. Investors today appear confident in the utility regulatory model since the threat of disruptive forces has been modest to date. However, the competitive economics of distributed energy resources, such as PV solar, have improved significantly based on technology innovation and government incentives and subsidies, including tax and tariff-shifting incentives. But with policies in place that encourage cross subsidization of proactive customers, those not able or willing to respond to change will not be able to bear the responsibility left behind by proactive DER participating customers. It should not be left to the utility investor to bear the cost of these subsidies and the threat to their investment value.

This paper encourages an immediate focus on revising state and federal policies that do not align the interests of customers and investors, particularly revising utility tariff structures in order to eliminate cross subsidies (by non-DER participants) and utility investor cost-recovery uncertainties. In addition, utilities and stakeholders must develop policies and strategies to reduce the risk of ongoing customer disruption, including assessing business models where utilities can add value to customers and investors by providing new services.

While the pace of disruption cannot be predicted, the mere fact that we are seeing the beginning of customer disruption and that there is a large universe of companies pursuing this opportunity highlight the importance of proactive and timely planning to address these challenges early on so that uneconomic disruption does not proceed further. Ultimately, all stakeholders must embrace change in technology and business models in order to maintain a viable utility industry.

The **Edison Electric Institute (EEI)** is the association of U.S. shareholder-owned electric companies. Our members serve 95% of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70% of the U.S. electric power industry. We also have as Affiliate members more than 80 International electric companies, and as Associate members more than 200 industry suppliers and related organizations.

Organized in 1933, EEI works closely with all of its members, representing their interests and advocating equitable policies in legislative and regulatory arenas.

EEI provides public policy leadership, critical industry data, strategic business intelligence, one-of-a-kind conferences and forums, and top-notch products and services.

For more information on EEI programs and activities, products and services, or membership, visit our Web site at www.eei.org.

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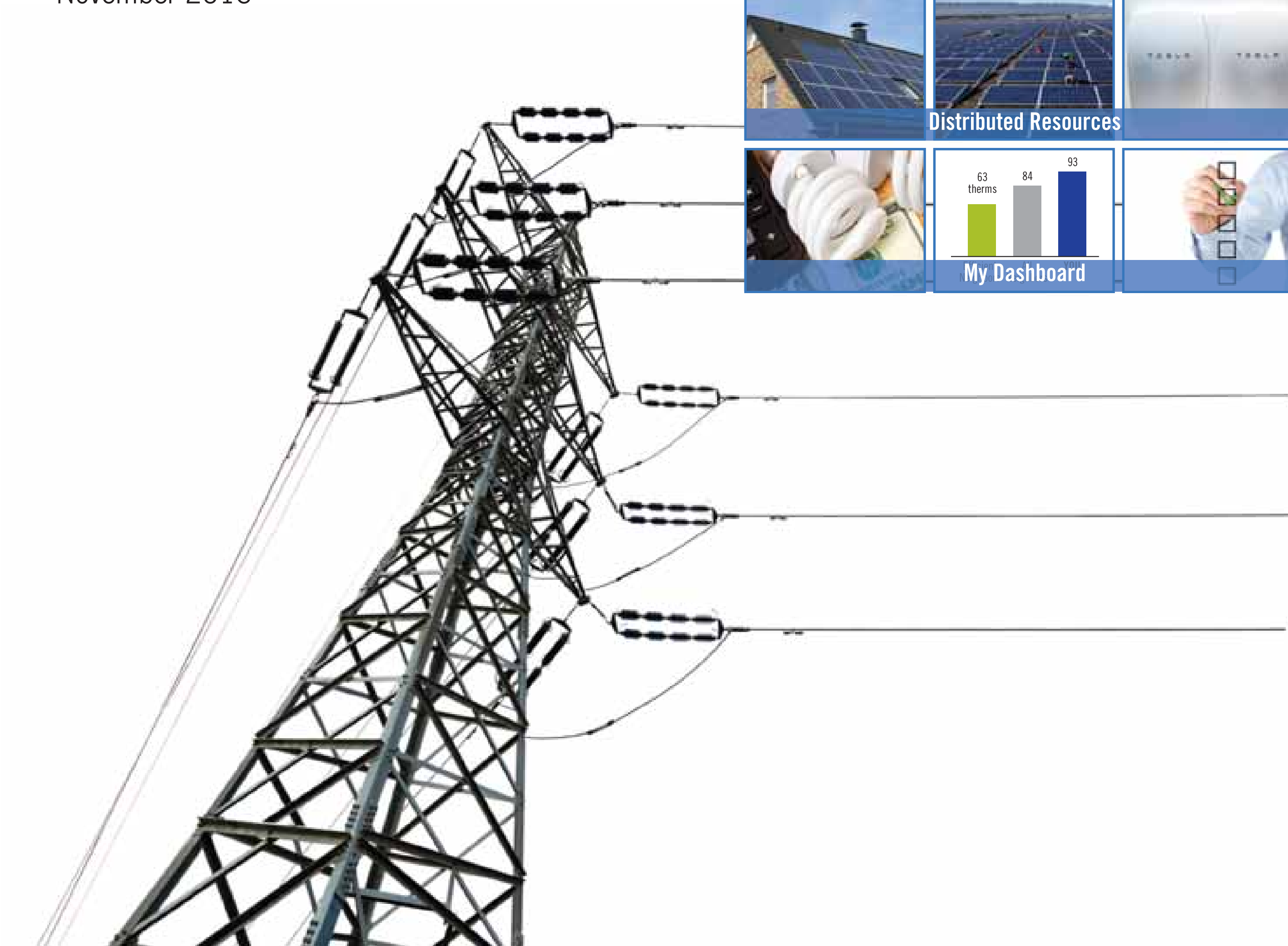
Ceres

Pathway to a 21st Century Electric Utility

November 2015



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About Ceres

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Peter is the Executive Director of Energy Infrastructure Advocates LLC, a strategic advisory consultancy focused on public policy supportive of utility and energy sector infrastructure development in a changing energy industry landscape.

Prior to the founding of EIA in 2012, Peter worked for over 30 years in investment banking, with a specialization in utility and power sector finance. Peter's banking experience includes capital markets advisory and transaction execution and strategic advisory services, including merger and acquisition and corporate finance advice. Peter's M&A experience includes all sectors of regulated utility and non-regulated power businesses. Throughout his career, Peter has been actively involved in outreach to regulators and policymakers, including work as an expert witness in regulatory proceedings and forums, presenting at industry and regulatory conferences on financial issues impacting utilities and power producers and in direct outreach on regulatory matters. In 2013, Peter authored a paper on Disruptive Challenges to the utility industry published by the EEI.

Peter's investment banking experience, includes prior experience at Macquarie Group, Bank of America, where he lead the Power and Utilities Corporate and Investment Banking effort, and Citigroup and Kidder Peabody, where he co-directed the Power & Utilities industry teams of each of those firms. Prior to investment banking, Peter worked for Arthur Andersen & Co.

Peter is a Director of the general partner of Enable Midstream Partners, LP, a midstream energy services provider and a Director of NextEra Energy Partners GP, an owner of renewable power generation. Peter is also a Director of Southwest Water Company, an infrastructure fund owned water and wastewater utility.

Peter holds an MBA in Finance from New York University and BBA in Accounting from Iona College. Peter practiced as a Certified Public Accountant until 1981. During 2008 to 2011, Peter was Co-Chairman of EEI's Wall Street Advisory Group.

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Pathway to a 21st Century Electric Utility

Commissioned By: Ceres
Authored By: Peter Kind

As a banker serving the U.S. utility industry for over 30 years, I have long questioned the impact of policy actions and regulatory mandates that threaten the revenue base of utilities and the industry's financial health. In 2013, I authored "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Energy Business," published by the Edison Electric Institute (EEI). That paper presented my views, looking through the lens of an investor, of the challenges confronting the long-term financial viability of the electric utility industry given its present business model.

Since the release of *"Disruptive Challenges,"* the forces outlined therein have continued to develop, particularly the pace of technological innovation and cost-curve improvements. Importantly, electric customers and the policy community have continued to foster key disruptive forces by confirming their support for customer energy supply choice, net energy metering and opposition to increased fixed utility charges. My positions have evolved in order to find solutions that can promote collaboration and alignment of interests.

In reviewing the constantly evolving landscape, I felt that it was important to provide an updated, more holistic perspective that aligns society's needs with the interests of utilities and their customers. In 2010, Ceres made an important contribution to the dialogue with the release of *"The 21st Century Electric Utility: Positioning for a Low-Carbon Future,"* and it seemed a natural fit to collaborate with Ceres on this new paper.

> **Utilities are not going away, because we require them to operate the electric grid, so why not expand the scope of their mandate to manage an environment in which consumers use energy and electricity more efficiently to create customer value and optimize the electricity system for the benefit of all?**

Utilities do an excellent job of what they are mandated to do—provide safe, reliable and affordable energy. Utilities are not going away, because we require them to operate the electric grid, so why not expand the scope of their mandate to manage an environment in which consumers use energy and electricity more efficiently to create customer value and optimize the electricity system for the benefit of all? In this environment, utilities will be incented to maximize customer and system value, as opposed to simply building infrastructure.

Given the importance of revising the utility industry model for the benefit of customers, society and utility investors, this paper is an expression of my evolved views in an effort to find common ground that will support a robust 21st Century Utility model.

Challenges Facing the Electric Utility Business Model

Over the past decade, a confluence of challenges facing the electric utility business model has stimulated active discussion among utility industry stakeholders. The challenges are the result of economic, demographic, behavioral, policy and technology trends, and are not expected to reverse. In fact, they are continuing to gain momentum, particularly the development of new technologies, continued reductions in renewable energy costs, and policymaker support for a revised vision of utility service that supports customer choice.

Utility sector investments, however, continue to trade close to all-time high valuations based on low interest rates. Threats to the utility sector are still in the early stages because customer adoption of new energy technologies remains low, but are growing. Furthermore, customers, rather than investors, are bearing the near-term cost of disruption through increased utility rates, somewhat offset by lower fuel costs.

The current 100-year-old utility business model does an excellent job of keeping the lights on, but it often does not align interests and behaviors or facilitate the policy goals and customer dynamics that exist in 2015.

Once investors begin to experience these challenges as a direct impact on the economic-return potential of their investments, however, the cost and availability of capital to fund the utility sector will suffer. Given that the industry relies on 30-plus-year investment recovery cycles, it is essential that capital deployed today be planned and rationalized to avoid future stranded costs, or investments that are no longer economical.

The current 100-year-old utility business model does an excellent job of keeping the lights on, but it often does not align interests and behaviors or facilitate the policy goals and customer dynamics that exist in 2015. To create the clean, efficient and sustainable energy future that all stakeholders seek, we must revisit the industry model to ensure alignment with customer and policy goals, while also ensuring that utilities and third-party providers are properly motivated to support their customer, societal and fiduciary obligations.

Policy and industry stakeholders in most states are neither proactively addressing industry model challenges from a comprehensive policy perspective, nor seeking the collaboration of all stakeholders to find a solution that benefits all parties. In New York, a closely watched initiative has policymakers defining a future in which the utility role involves managing the grid and acting as a platform provider for third parties. This role is not as investor friendly as utilities would desire. In many states, despite customer and policy opposition, electric utilities are proposing increases in fixed charges, which discourage energy efficiency and impact low-income customers. This lack of progress in stakeholder collaboration is ***not*** in our collective best interests.

While the cost structure of electric distribution utilities is predominantly of a fixed nature (i.e., not meaningfully impacted by volumes or operating variability), utility rate structures have typically authorized a small fixed-charge component. Pursuing an increase to fixed-charge recoveries is a tariff design tool that utilities have actively pursued since 2013 to mitigate revenue risk from the challenges they face.

However, there has been meaningful opposition on the part of customer interests and policymakers to utility proposals to significantly increase fixed charges. The policy of adopting monthly fixed-charge increases has several flaws—principally that such increases would remove the price signals needed to encourage energy efficiency and efficient resource deployment—that need to be considered when assessing alternatives through a lens by which all principal stakeholders benefit. This paper proposes several solutions to address the utility revenue challenge as an alternative to increased fixed charges, such as inclining block rates, reforming net energy metering, use of bidirectional meters, time-of-use rates, accountability incentives and identifying new revenue opportunities for utilities.

More broadly, this paper proposes a **new pathway to a 21st Century Electric Utility system** that creates benefits for customers, policymakers, utility capital providers and competitive service providers.

The key differentiators proposed in the pathway toward a new utility model are as follows:

a) engage the distribution utility to be at the center of integrating resources and stakeholder collaboration to achieve customer and policy objectives through accountability and incentives;
b) shift regulatory oversight to focus on integrated distribution system planning and development of transparent accountability metrics;
c) ensure that utility revenues will reflect incentives (or penalties) earned for accountability of results and new energy management services sourced through new resources, such as an energy management applications store; and
d) pursue cost-effective planning to identify the most efficient technologies to be employed, and cap customer incentives based on the most economical alternatives to achieve policy goals.

The paper first sets the stage by identifying the stakeholders and potential participants in a new industry model, summarizing the objectives and considerations of stakeholders, and reviewing the debate that is playing out, including actions by several of the more proactive states. It then lays out a vision for the 21st Century Utility and identifies foundational principles to support this vision before proposing the pathway. Given that we have over 50 states and districts that regulate our utilities, there will be no one-size-fits-all solution.

This paper proposes several solutions to address the utility revenue challenge as an alternative to increased fixed charges, such as inclining block rates, reforming net energy metering, use of bidirectional meters, time-of-use rates, accountability incentives and identifying new revenue opportunities for utilities.

The **vision** proposed for the 21st Century Utility model is relatively straightforward, and includes:

- enhanced reliability and resilience of the electric grid while retaining affordability;
- an increase in cleaner energy to protect our environment and global strategic interests;
- optimized system energy loads and electric-system efficiency to enhance cost efficiency and sustainability; and
- a focus on customer value, including service choices and ease of adoption.

Instead of maintaining our current policies, which encourage increased electric consumption and capital investments, the objective of the vision is to develop a model that enables customer value and service and achieves policy objectives to position us for the certainties of the future—particularly that the current concentration of fossil fuels in our energy mix poses significant risks to our economy and environment.

Because there is no reasonable threat over the foreseeable future of significant customer grid defection, a robust electric grid is a key component of a 21st Century Electric Utility, and thus, financially healthy utilities will be essential to maintaining and operating the grid.

The **foundational principles** or ground rules to support the achievement of this vision are as follows:

- financially viable utilities are essential to fund and support an enhanced electric grid;
- policymakers must promote clear policy goals as part of a comprehensive, integrated jurisdictional energy policy or 21st Century Utility model;
- commitment to engaging and empowering customers can help them make intelligent energy choices, including third-party engagement and access to necessary data; and
- equitable tariff structures promote fairness and policy goals.

The **pathway** proposed is one wherein policymakers task utilities with the **responsibility for** being at the center of coordinating and accelerating the refinement of our model for a 21st Century Electric Utility, and holds them accountable with penalties and incentives. On this pathway, policymakers will collaborate with stakeholders to develop and authorize the vision for the industry's future for customers and providers. Policymakers will then outline a comprehensive plan to realize their 21st Century Electric Utility model. The proposed pathway shifts regulatory oversight from being administered primarily through periodic rate cases to a forward-looking focus on planning, accountability and financial incentives for results achieved. Tariffs will be refined to address fairness, policy goals and provide price signals, consistent with enhancing system wide efficiency and environmental protection.

Regulators will create incentives and penalties to encourage and hold utilities accountable for achieving transparent goals and metrics to be outlined for measuring progress and success. **Technology innovators and third-party service providers** will collaborate with customers and utilities to create and refine products and services that support policy goals, engage customer interest and integrate efficiently with the grid. **Utilities** will partner with third-party providers and customers to provide reliable, affordable, clean energy in the most efficient way possible. **Customers** will be educated as to opportunities to deploy new services to enhance the value of their electric service and achieve societal benefits, such as reducing their environmental footprint.

Energy efficiency and system optimization, for example, have been an area of focus since the 1980s, and while progress has been made, the majority of customers have not taken advantage of the opportunities that can be realized. The American Council for an Efficient Energy Economy (ACEEE) estimates that a 40 to 60 percent reduction of electricity sales could be achieved by 2050 by harnessing the full suite of opportunities. On a pathway to a 21st Century Utility, we must redouble our efforts to achieve these savings by increasing customer education and giving utilities incentives to engage their customers in adopting such technologies. Because increased efficiency strikes at the revenue base of utilities, the proper incentives must be adopted so that utilities will be at least indifferent to the loss in electricity sales and ideally, be motivated to encourage energy efficiency.

In order to realize the societal benefits of a clean and efficient electric industry, each state should move forward now on a pathway to a 21st Century Utility model. Each state will have different challenges to confront, but the goal would be to develop several robust models that can be tested, compared and refined over time.

The Environmental Protection Agency's newly released **Clean Power Plan (CPP)** provides an excellent opportunity for states to consider their utility model as a component of their CPP compliance plan filings. The CPP sets standards for reducing greenhouse gas emissions from existing and new power plants, and calls for each state to provide its compliance plan by September 2016. The CPP will enable each state to reconsider its energy future and align state compliance plans with a pathway to a 21st Century Utility. Longer-term, customers, society and utility investors will benefit from proactive solutions.

Utilities have remained committed to their historical obligation to provide customers with safe, reliable and affordable service. As dynamics have evolved, society now expects that utilities will confront new priorities, such as protecting our environment and assisting customers in being more efficient with their energy usage. These new priorities challenge utilities' revenue and profitability levels and, thus, utility fiduciary obligations to their investors. A new industry model will need to provide opportunities for utilities to earn a reasonable return while providing society and customers the services they seek.

The proposed pathway shifts regulatory oversight from being administered primarily through periodic rate cases to a forward-looking focus on planning, accountability and financial incentives for results achieved.

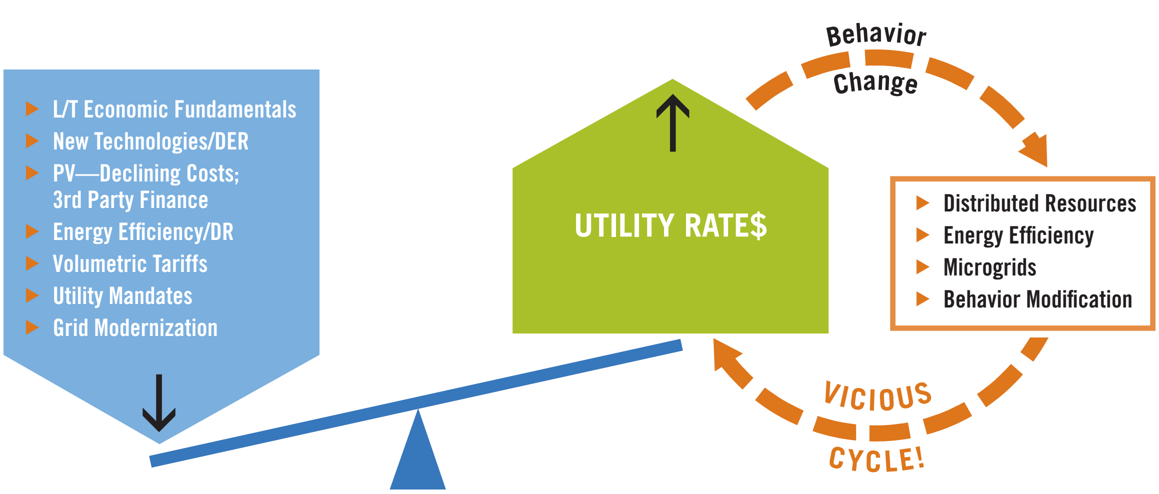
The Case for a 21st Century Electric Utility Model

Disruptive Forces—A Quick Review

Over the past several years there has been active discussion among utility industry stakeholders as to the confluence of challenges facing the industry business model. These challenges are considered long-term forces that are not expected to be reversed, and they encompass economic, demographic, behavioral, policy and technology trends. The principal challenges facing the utility model can be summarized as follows:

- slowing demographic (U.S. population) and economic growth opportunities have reduced electric consumption growth and customers' disposable income levels;
- customer interest in reducing energy usage and environmental impact has gained attention and interest, particularly among Millennials;
- public-policy goals seek to increase energy-efficiency adoption and clean-energy production and to reduce environmental emissions;
- price inflation and costs to deploy new grid technologies are increasing utility capital budgets and requiring increased electric rates (although rate increases have not in general outpaced inflation);
- customers now have enhanced options to save on their energy bills through programs that reward adoption of clean technologies (e.g., solar distributed energy resources combined with net energy metering programs); and
- U.S. regulatory models that are energy-usage based, regardless of load or time of day, constrain prospects for utility revenues and financial health.

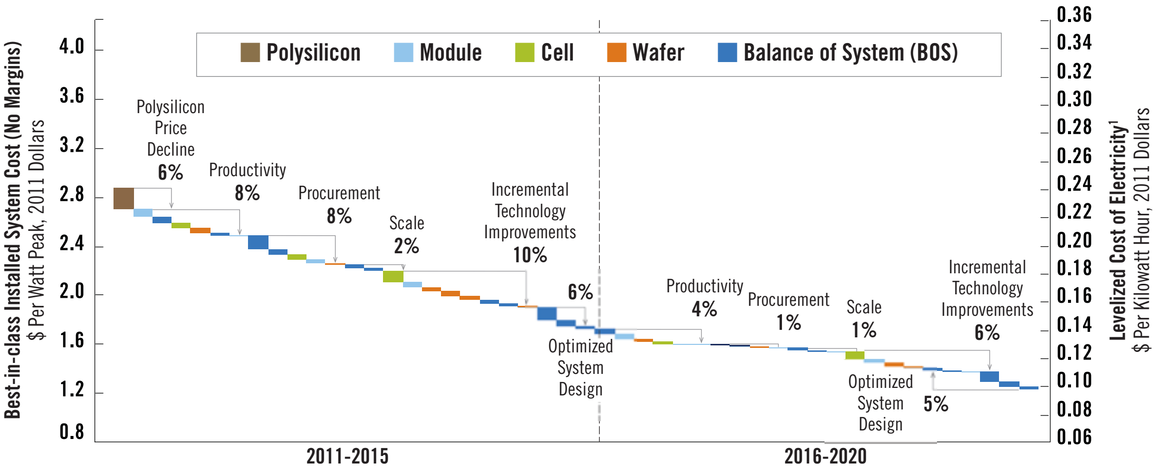
Figure 1: Disruptive Forces—Impact and Feeding of the Vicious Cycle



A confluence of factors are posing disruptive threats to the traditional utility business model.

All of these dynamics are at play while distributed energy resource (DER) economics continue to improve, due to improved technology, market competition and the advent of attractive customer financing options (see **Figures 2 and 3**, below). Left unattended, these challenges encourage a vicious cycle in which customers are motivated to self-generate (such as by rooftop solar) to avoid increasing utility prices, thereby leaving the cost to fund the electric grid to an increasingly smaller group of customers. And yet the grid is essential for DER technologies, particularly rooftop solar, because it allows customers to sell their surplus energy back to the utility. A 2013 study commissioned by the California Public Utilities Commission found, in fact, that due to net energy metering, residential DER customers in California paid approximately 50 percent less toward the fixed cost of providing utility service.[1]

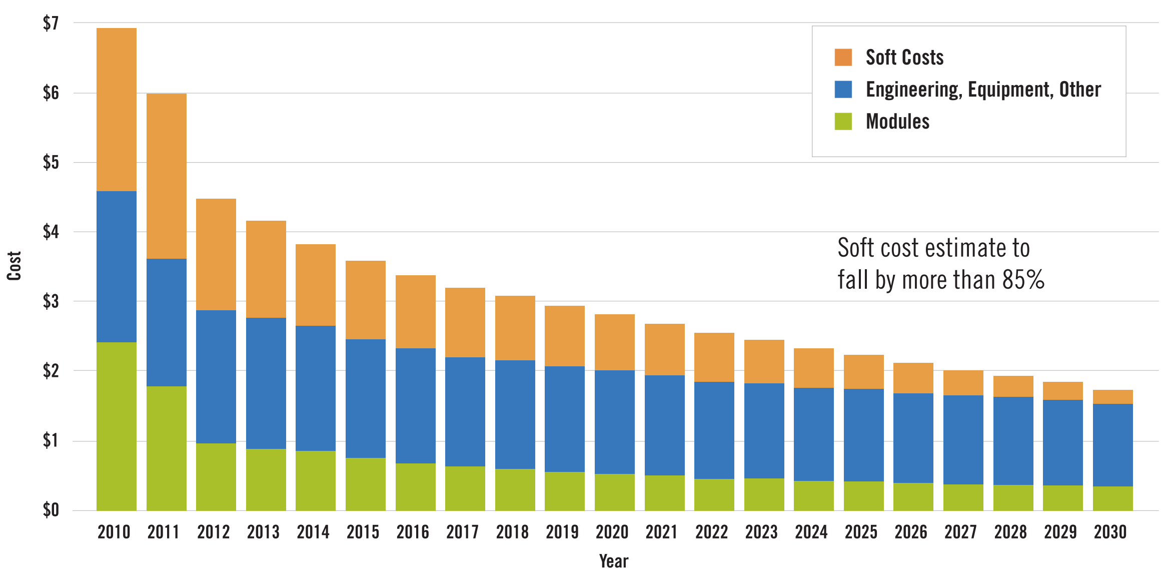
Figure 2: PV Cost Improvements—Innovation and Scale Drive Opportunities



1 Levelized cost of energy; assumptions: 7% weighted average cost of capital, annual operations and maintenance equivalent to 1% of system cost, 0.9% degradation per year, constant 2011 dollars, 15% margin at module level (engineering, procurement, and construction margin included in BOS costs).

Source: McKinsey & Company.

Figure 3: Average USA Price Per Watt for a New Solar System



Source: Bloomberg New Energy Finance.

1 Energy and Environmental Economics, Inc., "California Net Energy Metering Ratepayer Impacts Evaluation," Prepared for the California Public Utilities Commission, October 2013.

Clearly, the electric grid will continue to be essential to virtually all customers for the foreseeable future. In fact, the viable solar rooftop market—after factoring in home ownership, credit scores, locational positioning and suitability and NEM favorability—is currently projected to be approximately 20 percent of US households.[2] Thus, utilities must retain their financial viability to attract the capital required to support the grid. Most investors are not focused on these issues today due to low, though increasing, penetration of DERs and allowed cost recovery of "lost revenues" in future rate cases.

Other disrupted industries have reached the tipping point at which new products and services attain a penetration level and trajectory that challenge the viability of an old-line business and its access to capital. At that point in those challenged industries, financial access and viability are forever threatened. Kodak and Polaroid are prime examples of how disruptive forces (primarily technology in those cases) can destroy a company's financial value and capital access. Given the essential nature of utility services, however, a death spiral for the electric utility industry is not expected in the foreseeable future. Stakeholders must nevertheless be proactive to protect utilities' financial viability, given the industry's vital importance to our energy future.

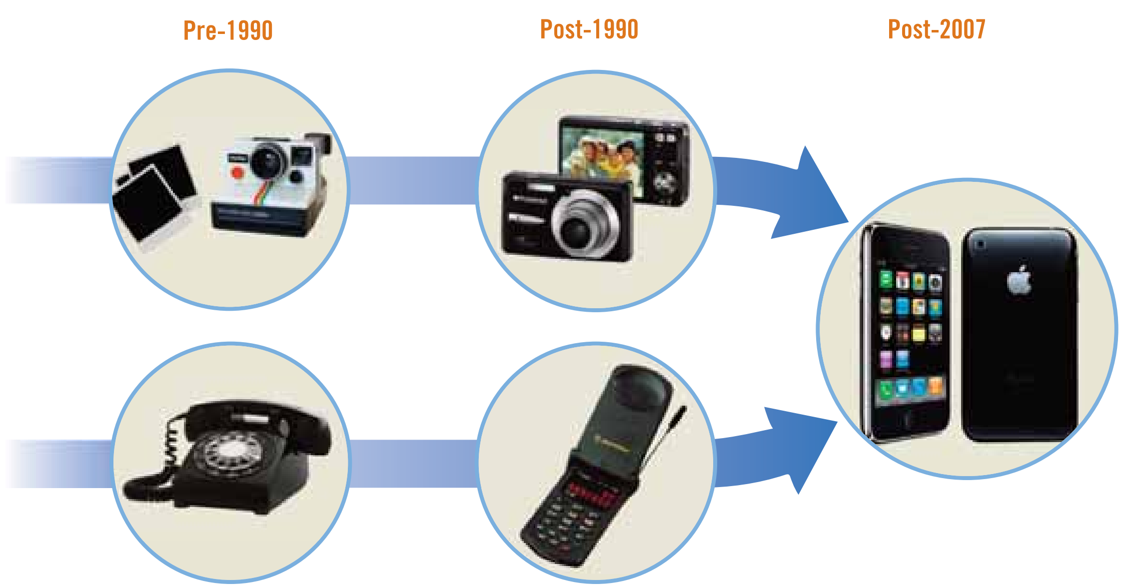
Other disrupted industries have reached the tipping point at which new products and services attain a penetration level and trajectory that challenge the viability of an old-line business and its access to capital.

Value and Future of the Electric Grid

While the "Disruptive Challenges" paper and others have drawn parallels between landline telephone deregulation and the electric utility model, there are important distinctions between the two. First, there is no known technology today by which electricity can be transported from location to location without a wire. Second, for many customers, installing the technology to disconnect from the grid would be prohibitively expensive, and/or they are not in the proper location or lack the ownership control (i.e., rent their homes) to deploy current DER technologies. In addition, industry experts believe there is great societal value created from the development of a robust grid and that grid defection creates barriers to enhancing and maintaining the electric system we require.

While industry discussion, including "Disruptive Challenges," gives examples of a scenario whereby certain customers could disconnect their access to the grid, or new construction could be grid independent (e.g., DER customers with storage), there is no reasonable scenario for **significant** customer exit from the grid for the foreseeable future. The only way to sell power back to the grid is to be connected to the grid. For DER customers, as an example, every time a new

Figure 4: Examples of Technology Disrupting Main Line Industries



2 GTM Research and Vox

customer installs rooftop solar, he or she is likely basing that economic decision on the ability to sell surplus renewable power back to the grid for at least 20 years.

The grid acts to enable the benefits of distributed resources through the sale of electricity to others and to enable commercial opportunities and transactions through the powering of our entire economy. In addition, the grid provides needed backup support for DERs and storage when renewable resources are not functioning or when demand exceeds system capacity. Thus, the electric grid is, and is expected to remain, the backbone of our electric energy system.

A robust electric grid is therefore required to achieve the greater reliability sought by all customers and to enhance access to additional bidirectional power inputs for DER customers. A study by Brattle Group, commissioned by the EEI in 2009, projected that the U.S. electric utility industry will need to invest between $1.5 and $2 trillion between 2010 and 2030 to maintain current levels of reliable electric supply.[3] To maintain a robust, responsive and resilient grid, we must have a structure in place that supports financially healthy utilities capable of attracting the significant capital required. Thus, the question of structuring tariffs to support the grid and other valuable services provided by utilities must be considered (see **Ratemaking and Tariff Design**, page 29).

The Stakeholders in a 21st Century Electric Utility Sector

It is critical that any attempt to develop 21st century approaches seek as much alignment as possible among the key stakeholders involved in electric utility planning. The stakeholders in electric utility debates continue to evolve as priorities and key issues are refined or emerge, and today include residential, commercial and industrial customers, technology sector providers, utilities and their shareholders.

Residential Customers

Residential customers continue to have significant clout in the evolution of policy due to their voting power and large numbers. Groups representing low-income residents and seniors (who often live on a fixed income) tend to have influence because service cost is a high priority. Another prominent voice in the residential class debate is environmental advocacy groups that seek a focus on environmental stewardship and sustainability. Between these groups, there is alignment that aims to avoid high fixed charges for utility services and supports well-designed inclining block rates. Inclining block rates aid low-income residents and seniors by creating a progressive rate tariff: the more you use, the more you pay per unit. From an environmental policy perspective, inclining block rates provide an incentive to conserve energy usage by charging higher rates to the higher energy users.

Commercial and Industrial Customers

Although large commercial and industrial customers lack voting clout, they are active voices in the development of energy policy. Policymakers need to be aware of large customers' impact on the economic growth and vitality of a region; low utility rates will retain and attract them. While energy prices and availability are not the only factors in the drive for corporate competitiveness, large businesses can relocate when the local policy environment does not support their competitive position. In addition, large commercial and industrial customers (including General Electric, Procter & Gamble, Microsoft, Coca Cola and Walmart) are increasingly focusing on their sustainability profiles, including procurement of renewable energy. Thus, as stakeholders consider how to retain current business customers and develop and attract new industries, energy prices, reliability and access to clean energy will be key factors.

Policymakers

Policymakers and regulators tend to be attuned to their most vocal customers, because their voting power controls the ongoing "seat" of the policymakers. It is clear from the wide array of state-mandated renewable portfolio standards, energy-efficiency programs, net energy metering tariffs, and inclining block rates that policymakers are focused on clean energy, consumer choice, efficiency and price signaling. One question this paper seeks to address is whether policymakers are doing all they reasonably can to accelerate programs to optimize these objectives.

Technology Sector Participants

A recent entrant into the energy policy debate is technology sector participants, particularly renewable-energy providers. These entities are selling their products to customers directly and, as a result, customers use less electric service from the utility. While many of these providers understand that they need to cooperate with utilities to provide customers the benefit of their product offering, there is typically no clear, approved path for these competitive providers to partner with utilities to promote their offerings in a way that benefits both the technology provider and the utility. The interaction between technology and utility providers is often adversarial, with the technology provider seeking to sell products that will limit electric sales and thus adversely impact utility revenues. Utilities have therefore been hesitant to partner

3 Brattle Group, ",“In Transforming America's Power Industry, The Investment Challenge 2010—2030," (2009).

with these third-party providers, which have built strong policy advocacy efforts and industry organizations because such activities are essential to their future viability.

Utilities and Their Investors

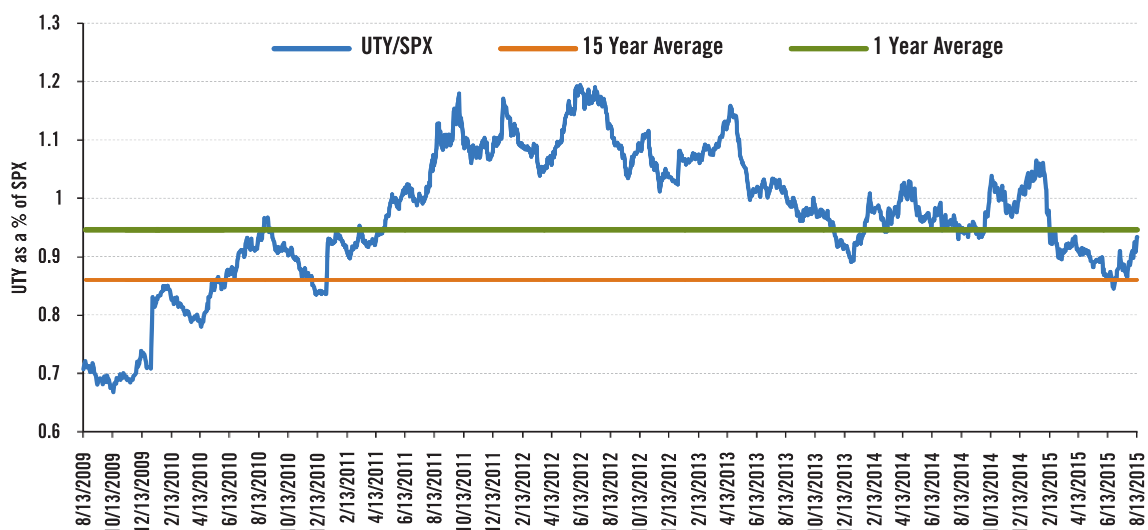
Utilities have many masters, but their principal obligations are to provide safe, clean, reliable and affordable electric service to customers and to earn a fair return on capital invested. Electric utilities generally do an excellent job of meeting customer-service expectations. A comprehensive study, "Exploring the Reliability of U.S. Electric Utilities," showed that reliability, despite extreme weather events, averages above 99.9 percent.[4] However, extreme weather events, such as hurricanes Katrina (2005), Irene (2011) and Sandy (2012) and devastating tornadoes such as Joplin (2011) are examples of the need for enhanced electric grid "hardening" and resilience to protect our citizens and economy.

Achieving an adequate return on capital, in particular in the short term, depends upon selling more energy, because that is how tariffs tend to be structured. Utility boards of directors typically structure utility management compensation programs based on achieving reliability factors and a larger weighting to financial returns. This is more customer friendly than other industries, in which executive compensation is based solely on market share and profit goals. While 25 states offer incentives for efficiency results,[5] these programs tend to offer limited financial incentives to utilities for promoting energy-efficiency services or clean technologies.

For example, while California has been proactive in providing incentives to utilities for encouraging energy efficiency, the incentives reported in 2014 were less than 1.25 percent of pre-tax operating income for the largest California utilities, or less than 0.1 percent in additional return on equity (ROE), after tax. Locating the disclosure of earned incentives in the California utilities' SEC filings is like finding a needle in a haystack. That makes it hard for investors to reflect in their valuation assessment a material, recurring, transparent and timely (in California there is a several-year lag in calculation) incentive mechanism. **While incentives should align behaviors, insignificant and nontransparent levels of incentives will not drive behavioral change and realization of optimal results.**

While utilities are interested in and impacted by the debate on regulatory models, their interactions are challenged by a skeptical policymaker environment, which often presumes that any position by an electric utility reflects a self-serving benefit. Thus, utilities are in a challenging position when it comes to leading or proposing solutions. As a result, utilities tend to be defensive in their approach and often lack the vision or motivation to identify areas where the business model can be enhanced for the benefit of their customers and investors. Instead of arguing for incentive mechanisms, many utilities have been seeking to increase fixed charges, while customers and policymakers are vehemently opposed to such action. An evolved approach would focus on common ground with win4 (i.e. beneficial to customers, policy, competitive providers and utilities) opportunities.

Figure 5: Utilities Are Valued Above 15-year Averages and Comparable to S&P 500

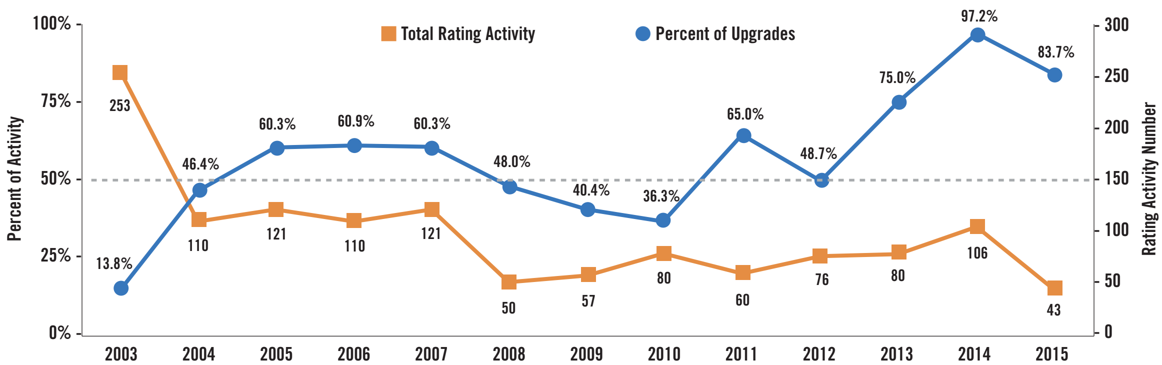


Source: BofA Merrill Lynch Global Research, Bloomberg

4 Larsen, Sweeney, LaCommare and Eto, "Exploring the Reliability of U.S. Electric Utilities," (2012).

5 ACEEE Economy, "Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency," June 2015.

Figure 6: Credit Rating Agency Actions Suggest Improving Credit Quality



Source: Edison Electric Institute, Fitch Ratings, Moody's, Standard & Poor's

Utility investors as a group are not interested in change, because the results they have realized from their investments in the sector have provided stable returns. Investors fear that any change could lead to an adverse impact on short-term results and that the defensive investment attributes they have sought—low price volatility, stable economic returns and cash dividend yields—may be compromised. As stated above, boards have structured the bulk of utility management compensation on achieving profit objectives, in addition to reliability performance. Investors are generally comfortable with the transparency of the utility model, despite the argument that the industry model may no longer be appropriate or viable in a changing environment. In fact, utility stock prices today are near all-time highs on a price and valuation multiples basis. Current valuation metric levels (See **Figure 5**) suggest that investors continue to view utilities as an attractive place to deploy capital.

If a material change in business financial performance were to be realized, investors would likely become less sanguine about deploying capital in the sector. But the majority of utility-sector investment analysts and rating agencies see little to be concerned about as long as the penetration rate of efficiency and clean-energy resources is low and regulators allow utilities to recover lost revenues in the near future. In fact, utility credit ratings have solidified over the past several years, particularly distribution utilities, as the economy has stabilized and industry restructuring volatility from the 2000 - 2005 era has been resolved. (See **Figure 6)** So, while short-term dynamics are the current focal point of the investment community, longer-term dynamics should be a key consideration in order to avoid disruption to the utility industry, its customers and our economy.

So, while short-term dynamics are the current focal point of the investment community, longer-term dynamics should be a key consideration in order to avoid disruption to the utility industry, its customers and our economy.

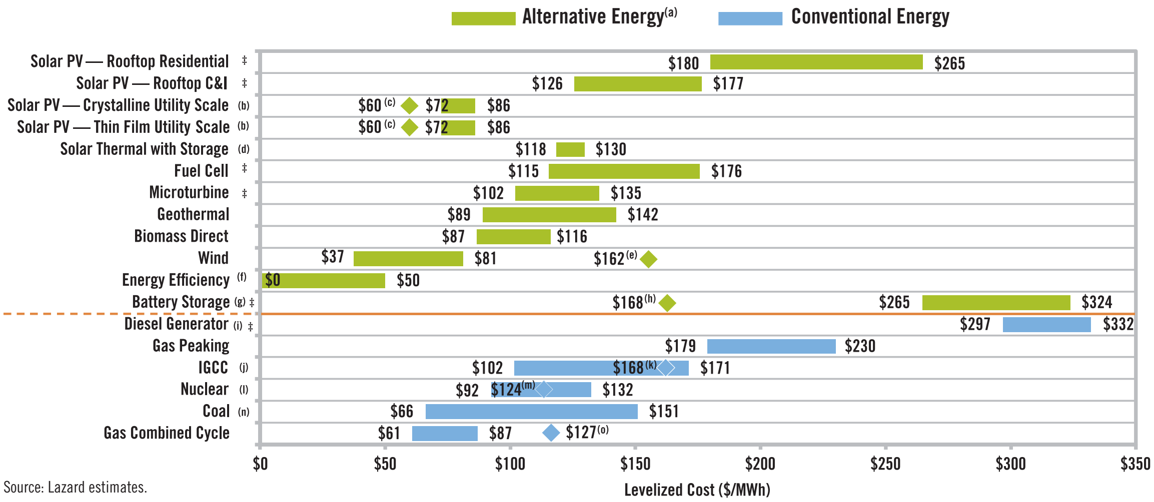
Utility investors, individually or as a group, are not often at the table in discussions on energy policy. Many institutional investors prefer the current utility business model and deal with change by selling the sector or certain investments when it starts to evolve in a way that appears more risky. While some investors, such as those in the $13 trillion Investor Network on Climate Risk (INCR) have become involved in clean-energy policy advocacy, it is still rare to see major institutional investors show up to address a state regulatory policy issue or to support a utility rate case.

Key Stakeholder Issues

Although unanimous agreement on the objectives for a 21st century electric utility industry model is not likely to be achieved, there appears to be solid customer, policymaker and utility support for key foundational objectives for the future industry. Key objectives include improved reliability and resilience of electric service, a cleaner sustainable electric supply and customer cost stability.

Customer cost stability is difficult to achieve in a regulatory construct that seeks (i) usage-based pricing, (ii) customer choice for self-generation of electric supply, compensated by non-DER customers, and (iii) limits on utilities' ability to serve and earn revenues from new 21st Century Utility services. Moreover, the investment required to harden the grid to improve reliability and resilience and provide a cleaner mix of energy resources will increase the cost of

Figure 7: Unsubsidized Levelized Cost of Energy Comparison—September 2017



Source: Lazard estimates.

Certain Alternative Energy generation technologies are cost-competitive with conventional generation technologies under some scenarios; such observation does not take into account potential social and environmental externalities (e.g., social costs of distributed generation, environmental consequences of certain conventional generation technologies, etc.) or reliability-related considerations (e.g., transmission and back-up generation costs associated with certain Alternative Energy generation technologies). Diamonds typically represent expected cost in 2017, wind is for offshore, for more information see https://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf

providing service. Despite improving economics, the cost of clean energy, excluding externalities, will likely be more expensive than the current embedded cost of existing generation, because investment and backup capacity are required to support renewable supplies, which are intermittent. Given current utility pricing policies that do not consider externalities, the cost of electric service is expected to increase over time. However, as shown in **Figure 7**, clean energy is expected to become increasingly competitive with traditional fossil energy sources, even before considering carbon costs.

One of the key disputes in the discussion of a 21st Century Utility is the value of clean energy resources. Currently, neither the cost of carbon nor the system wide benefits of a clean-energy strategy, such as reduced system losses and transmission needs, are fully factored into the price of electric power. When the cost of carbon and other externalities are reflected in the cost of energy, the cost to customers will likely prove the long-term benefit of a clean-energy strategy. With the appropriate policies and alignment of interests, the value of electric service can be enhanced. For instance, optimizing our system and the use of energy can reduce the need for new peaking capacity and related incremental infrastructure.

Additional objectives, of policymakers and engaged customers, include system and energy-efficiency optimization, price signals to encourage economic efficiency and optimization, and regional economic growth. But without encouraging efficiency (via technology, price signals and targeted incentives) it will be quite difficult to optimize the primary objective of enhanced price stability, given that incremental resources and investment would be required to support incremental consumption.

J.D. Power, a leading global market-research firm, evaluates industries to understand what drives customer interests, loyalty and retention. In J.D. Power's recent rankings of utility customers, their analysis prioritizes customer attributes as follows:

	Customers	
	Residential[6]	Business[7]
Power Quality and Reliability	1	1
Price	2	4
Billing and Payment	3	2
Corporate Citizenship	4	3
Communications	5	5
Customer Service	6	6

Residential customers are primarily focused on power quality, reliability and price. Interest in new technologies and environmental stewardship does not reflect separate categories but rather contributing factors in the price and

6 J.D. Power and Associates, 2015 Electric Utility Residential Satisfaction Survey.

7 J.D. Power and Associates, 2015 Electric Utility Business Customer Satisfaction Survey.

corporate citizenship scores. Industry data show that a relatively low percentage (less than 1 percent nationally)[8] of utility customers are currently seeking new technologies and choosing to self-generate from renewables. Customers' primary focus today is on reliability and price. A much smaller subset of customers are **proactive** in initiating the adoption of energy-efficiency and clean-energy technologies, but it is a group that is growing rapidly and is expected to increase dramatically in the coming years.

Energy Efficiency—A Growing Opportunity

One of the most significant opportunities to enhance both customer value and environmental benefit is the expansion of energy efficiency. Presently, however, customer adoption rates are low. Policy frameworks need to develop incentives for overcoming the barriers to adoption.

A study by the Edison Foundation on the impacts of energy efficiency at a national level shows that energy efficiency is increasing, but amounted to only 3.4 percent of total 2012 electric energy sales.[9] Another study prepared for the Edison Foundation found that when energy-efficiency savings are combined with enhanced building codes and standards, such savings will increase by 2035 from current levels to 5.6 percent of total electric energy use.[10] While any increase in the adoption of energy-efficiency tools is a positive development, economic studies indicate that much more is achievable and would benefit both customers and the environment.

Leading factors in the low adoption rates for energy efficiency include a lack of general awareness of opportunities (particularly because customers cannot price-shop for another utility provider), lack of trust in third-party providers (due to ongoing "junk" mailings and cold calling), the cost to implement new technologies or services when up-front investment is required, and the fact that customers are too busy to learn about opportunities that may be consistent with their long-term economic and environmental interests.

A recent study by the ACEEE, for example, found that energy-efficiency opportunities could reduce electric sales by 40 to 60 percent from current 2030 forecasts, based on intelligent efficiency advances, zero-net-energy building standards and improved efficiency of appliances and technology. The study also noted significant progress in the energy intensity of our economy from 1980 to 2014 due to structural changes (e.g., the reduction of our manufacturing base) and improved efficiency of appliances, new buildings and electric infrastructure.[11] Thus, the opportunity to increase energy efficiency is substantial, but will require the focus of stakeholders to overcome the barriers to adoption.

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Large (commercial and industrial) customers, being focused on profit, are savvier than the residential class as to their awareness of cost-saving opportunities. Given capital availability constraints, however, commercial customers tend to demonstrate high return-on-investment hurdle rates (i.e., short payback periods) to invest capital in activities not directly related to their core product or service offering. This factor limits implementation of investments that would be of long-term benefit to the customer specifically and for society overall.

Policymakers and regulators are clearly intent on promoting customer choice of energy supply and increased renewable energy output. Twenty-nine states have Renewable Portfolio Standards (RPS), 24 states have energy-efficiency resource standards and 43 states have net energy metering.[12] Yet the approach to realizing this objective has primarily relied on customers taking the initiative to investigate new opportunities or responding to utility mailers regarding pilot programs, which are adopted by a very low percentage of customers. While there are many providers in various markets that are seeking to sell their technologies and services, customers often don't know whom to trust in this complex arena and are not familiar with the alternatives.

Why not engage utilities and offer them incentives to assist in accelerating these objectives? Utilities are well positioned to assist their customers in learning about and deploying energy-saving technologies, but they need both increased incentives and accountability for doing so. What we see from the success of smartphone applications ("apps") is that customers want "low-touch" solutions that can be implemented and monitored with ease. While that may not be possible for all services, the smartphone app

8 Solar Electric Power Association, 2014 Power Statistics

9 Edison Foundation Institute for Electric Innovation, "Summary of Electric Utility Customer-Funded Energy Efficiency Savings, Expenditures and Budgets", (2014).

10 EnerNoc Utility Solutions Consulting, "Factors Affecting Electricity Consumption in the U.S. (2010–2035),"), (2013).

11 ACEEE, "Energy Efficiency in the United States: 35 Years and Counting," June 2015.

12 ACEEE website, State Energy Efficiency Planning.

is today's gold standard for engaging customer interest. The exciting news is that the advancement of sensor technology and automated controls is creating new possibilities for low-touch efficiency applications in the energy sector (e.g., Nest, a learning, programmable thermostat).

Many observers believe that there is a meaningful aversion on the part of regulators to determining how utilities should be compensated for providing such new services. Thus, the utility role is neglected in favor of competitive industry players, who are *not* well known by customers, to drive this important objective. In fact, there is a logical scenario, to be outlined later, in which competitive third-party providers collaborate and partner with utilities to accelerate the adoption of their products and services.

Finally, although utilities are interested in providing excellent service to customers, they also have a fiduciary obligation to support their investment value by earning a fair economic return on the capital employed in the business. In most jurisdictions, utilities earn revenues based on capital invested, and such revenues are recovered through customer usage. By promoting activities that reduce usage, utilities are working against one of their core missions and their fiduciary duty, which is to earn a fair return on invested capital. Thus, achieving stakeholder objectives regarding energy efficiency and clean-energy technologies may be best accomplished by providing incentives to customers and providers. In most business models, businesses are motivated to sell new services because this enhances revenue. In our present utility business model, utilities realize a "penalty" to their revenues by encouraging the deployment of our current policy objectives, such as energy efficiency. This creates an inherent conflict that requires logical solutions, such as "revenue decoupling," described later, which breaks the link between energy sales and revenue, to align utility and customer interests.

A Vision for the 21st Century Electric Utility

If we could start with a clean sheet of paper, how would electric utility services be structured? We would want to ensure that there was alignment of policy, customer and investor goals in order to structure a product offering that satisfied the best interests of all major stakeholders, a win4. Such a service offering would maintain and build on the high electric reliability we have today; allow customers to benefit from the latest, most economical technologies to optimize the efficiency of their energy service; be environmentally friendly; and seek efficient economic deployment of resources and, thus, capital investment.

Policymakers would seek optimal economic deployment of the system to ensure reliability and capital efficiency. They would expect deployment of resources consistent with local, regional and national environmental policy goals. They would ensure that price signals be provided to customers so that the system was used efficiently to manage systemwide costs (both embedded and future deployment). Finally, policymakers would want to see fairly stable customer prices, to provide customers more certainty and help realize a competitive cost of service that promoted economic growth in the region.

This efficient deployment of renewables, consistent with a utility cost-effectiveness plan, would seek the most economical and location-efficient technology to provide the best resource base for the benefit of the entire system.

Utilities in this optimal environment would aim to offer a suite of products and services to achieve customer and policymaker objectives, and they would earn at their cost of capital (as deemed appropriate by the marketplace), or be given incentives to earn above it, for meeting these objectives. In a transparent and predictable business environment the cost of capital is lower, and the availability of capital is greater, than for less transparent, less stable businesses. Investors seek a business that offers growth potential as well, because a business without growth offers only a bond-like investment.

Competitive service providers would partner and collaborate with utilities to refine their products, optimize customer-acquisition costs and increase their share of market. In other words, they would partner with utilities to enhance their collective profit potential. To aid in identifying opportunities, competitive providers might avail themselves of defined, non-customer-sensitive electric system data. Policymakers would decide what information could be provided without compromising customer and system security.

How would a 21st Century Utility operate? It would target optimal use of diverse (hydro, solar, wind, biomass, efficiency, demand response, storage and Combined Heat and Power (CHP) renewable or low-cost electric energy resources that would be backstopped and supported by other clean, baseload energy sources. This efficient deployment of renewables, consistent with a utility cost-effectiveness plan, would seek the most economical and location-efficient technology to provide the best resource base for the benefit of the entire system. For example, in addition to residential rooftop PV solar systems, which do not consider optimal location or technology efficiency, the resource base would include a significant component of DER, community or utility-scale solar, intentionally located to enhance grid and system efficiency. The system would look to include efficient deployment of demand response and microgrids in those areas where reliability was of paramount importance (e.g., regions with high concentrations of hospitals, senior centers and schools) to protect them from weather and other emergency events.

Energy Management Applications Store

Over the past several years we have witnessed explosive success and customer interest in software applications that integrate with smartphones and tablets to provide easy and fun access to powerful software tools. These apps provide an array of services and information at the touch of a button. Why not create a customer-focused energy management application page, or "store," that would allow customers to explore a range of product and service alternatives to save energy and money? The objective of such a store would be to:

1) introduce an available product or service alternative;
2) provide information to educate the customer;
3) highlight quality vendors to provide the service, as appropriate;
4) provide click-through to order the product, arrange for an estimate or get further information; and
5) monitor results from using the product.

Ease of access to robust information and service ordering would be effective in engaging and empowering customers. Customers could be offered demand response, load management and time-of-use products that could be operated from their smartphone or other device. "My Dashboard" icons could support "shadow billing" to assess the potential savings from efficiency applications and other service opportunities. Customers' ability to arrange for the installation, operation and oversight of these services would be as easy as the touch of a button. Their total savings would be presented on the app so that they could see the benefit of their actions and understand how their usage and savings opportunities compare to their neighbors. This vision is not futuristic, because such tools and products exist today. The 75 percent of Americans with smartphones (expected to reach 80 to 85 percent by December 2015) or 87 percent with Internet connections would be able to access these services easily.[13]

The question remains: Who is best positioned to host the energy management app store—the government, the utility or some other sponsor? There is no reason that such an approach need be exclusive to one provider. The challenge is how to achieve the most traction from such an effort and create an environment in which customers have confidence that the information is objectively presented. Given an objective of increasing customer adoption of new technologies, utilities appear best positioned to be a logical host of this application store. They have the ability to provide usage data and objectively present information on services. In addition, utilities are best positioned to track and aggregate results of products and services to present to current and potential customers.

Policymakers would have to decide how to compensate utilities for providing this service. The Apple model is worthy of consideration. Apple hosts the App Store on its system and earns a fee from application developers (e.g., competitive energy solution providers) when users download apps. In the energy management model, third-party providers could compensate utilities for each customer click or purchase of a product or service. This model would likely result in a cost-effective tool for third-party providers to reach customers.

Importantly, the energy management application store by itself will not be sufficient to drive results without continued efforts by third-party providers to develop new efficiency technologies and by policymakers and utilities to design programs and customer education initiatives.

Figure 8: Energy Management Applications Store

13 comScore, "U.S. Smartphone Market Share Report,", February 2015.

Incentives would optimize expenditures and thereby moderate customer rate increases to help reform the utility model and manage behaviors. By realizing efficiency and system-load optimization, and considering tools such as the UK's Totex (see **Experiences in Selected States and the UK**, page 25), we should be able to moderate capital investment levels. For utilities, these incentives will offset reduced growth opportunities for investors and, most important, encourage the achievement of customer and policy objectives.

The challenge is that we are not starting from a clean slate, and while we have an excellent quality of essential utility service, the shift to the 21st Century Utility model requires complex transitions that will be heavily debated by stakeholders.

Examples of such transitional issues include:

- phasing in new clean-energy resources while phasing out less clean resources;
- phasing out current subsidy structures for DER users to an economic-value-driven incentive model;
- enhancing customer engagement in pursuit of optimal use of efficiency resources through continued focus on awareness, education and customer incentive programs; and
- regulatory reform to align interests, incentives and metrics for achieving accountability of results.

In order to achieve these goals, we need to create a transition plan that embraces the end-state vision. For that we need policy leadership, clear goals, alignment of interests and accountability.

The vision for the 21st Century Utility can be summarized in four simple points:

- enhanced reliability and resilience of the electric grid while retaining affordability;
- an increase in cleaner energy to protect our environment and global strategic interests;

Technology Game Changers

Although it is a mature industry, the electricity sector has become increasingly dynamic. New forms of technology are in development that will significantly shape the future of the utility business. Given the large capital investment required to fund this sector, and its essential and pervasive involvement in our communities, an important consideration to factor in to the development of the 21st Century Utility industry framework is how customers and utilities will deploy and address new technologies, including those on the horizon that have not yet achieved commercial viability.

Policy will be an enabling driver of many of these game changers. Policymakers should be proactive in considering how best to accelerate each of these opportunities in a 21st Century Utility model to maximize their potential economic and environmental benefits. Potential game-changing technologies such as the following could dramatically reshape the utility business.

- **Grid scale and customer-owned battery storage units** allow electricity to be stored when not required for immediate use and thereby dramatically enhance the value of intermittent resources, such as solar and wind power. They also allow customers to buy power from the electrical grid when prices are lowest and use their own energy at more expensive times. This is a technology-driven opportunity.
- **Electric vehicles** create potential for substantial additional electric demands (expected to be off-peak) for charging batteries and could discharge energy back into the system when the charge has more value as a pure electric energy source. This is a technology-, policy- and customer-preference-driven game changer that could significantly reduce pollution from the transportation sector.
- **Combined heat and power** standards for all large, continuously deployed energy loads (hospitals, hotels, prisons, etc.) optimize BTU consumption by leveraging waste heat into electric energy and steam-heating loads. This is a policy-driven game changer using incentives.
- **Enhanced building standards** can promote energy efficiency and strive to reach net-energy-neutral status. This requires policy to mandate that new construction and remodeling achieve higher efficiency standards. According to a study prepared for the IEEE , aggressive building codes and standards would achieve a 17 percent reduction in electric usage by 2035.[14]
- **Appliance standards** can compel all new major energy-using appliances to operate at best-in-class efficiency levels and support Internet adoptability for purposes of controlling technology use. This is a policy-driven game changer.
- **Big data analytics** can be leveraged to enable intelligent efficiency technologies. This is a technology- and policy-driven game changer.
- **Cost-effectiveness planning protocols** can be applied, both for resources and systemwide, including renewable adoption, promoting the most efficient resources to provide systemwide benefits. This is a policy-driven game changer.

Most of these game changers will allow for more efficient deployment of system resources (e.g., storage, CHP, building and appliance standards). While electric vehicles will increase off-peak electric consumption, they offer the opportunity for storage optimization. All of these listed items will require incremental capital investment, either on the grid or behind the meter.

14 EnerNoc Utility Solutions Consulting, "Factors Affecting Electricity Consumption in the U.S. (2010—2035)," (2013).

- optimized system energy loads and electric-system efficiency to enhance cost efficiency and sustainability; and
- a focus on customer value, including service choices and ease of adoption.

Reliability and Resilience

Few question the priority and importance of enhancing the reliability and resilience of electric service. While our electric system is highly reliable, recent weather events and the reliability needs of our increasingly technology-dependent economy are ample proof that we require exceptionally high reliability and resilience to fuel our economy. As in most areas of strategic importance, we cannot just maintain the status quo, but must be committed to continuous improvement of our electric system to support new technologies and the competitiveness and growth of our economy.

Increased Clean Energy

Most Americans believe that preserving a clean environment and addressing climate change are essential priorities. Gallup polling shows that only 24 percent of Americans have no concerns as to the quality of the environment (which is down from 29 percent in 2010).[15] Opposition to developing a cleaner energy mix tends to highlight the near-term economic impact (jobs and costs to customers), but momentum is clearly building toward a cleaner energy mix. In support of a clean energy future, (i) 36 states plus D.C. have either renewable portfolio standards (29 states plus D.C.) or renewable portfolio goals (7 states), (ii) 23 states have energy efficiency resource standards, and (iii) the US EPA recently released the Clean Power Plan (which aims for a 32 percent reduction in greenhouse gas emissions by 2030).[16]

Optimizing the use of our energy infrastructure will enhance our economic growth potential by increasing customer discretionary income and reducing costly energy emissions.

Optimized Energy System

Optimizing the use of our energy infrastructure will enhance our economic growth potential by increasing customer discretionary income and reducing costly energy emissions. Optimization of resources includes efficient energy consumption, spreading usage to off-peak periods and reducing the need to invest in incremental energy infrastructure. In doing so, current and future costs of electric service can be proactively managed to enhance value for customers. System energy loads should be optimized, not simply individual customer energy loads. For example, if there are better ways to enhance the efficiency of the grid (vs. behind the meter), all customers benefit equally from this investment. Examples include community solar and grid-level storage, as compared with customer DER application of such technologies. *This is not to suggest that we mandate one renewable resource over another, but that we pursue the most cost-efficient energy sources, either through new-construction plans or by capping incentives on DERs consistent with the most cost-effective clean-energy options.*

Con Ed's Brooklyn-Queens Program

An interesting example of deploying innovative solutions to achieve the goals of a 21st Century Utility is Con Ed's Brooklyn-Queens Demand Management Program (BQDM). The BQDM seeks to reduce demand by 52 megawatts via customer-side and utility-side solutions in order to avoid spending $1 billion on a new substation and related electric infrastructure. This initiative will provide incentives to participating customers and to Con Ed and will result in lower utility rates for all customers.

Customer Value

This is a new area of focus for utilities. Prior to DER and efficiency applications, utilities were responsible for meeting system needs, and customers were viewed as "ratepayers." When customers have alternatives, service providers must focus on providing customer value. Utilities are in the process of transforming to customer-focused organizations with an expanding choice of energy technology options. This is a work in progress, and many utilities may not understand the significance of this change. The focus on customer value also includes ease of product adoption. We live in a complex world in which many interests compete for our time. Value to customers is not just about product quality and cost of service, but includes making it easier for customers to learn about and, if appropriate, adopt alternatives.

To build such an industry, we will need foundational principles to support the vision and a pathway to reach it.

15 Gallup, Gallup Social Series: Environment, March 2015.

16 ACEEE website, State Energy Efficiency Planning.

Foundational Principles to Support a 21st Century Electric Utility

A durable building or organization requires a strong foundation to support its structure. The prior section outlined the vision for a 21st Century Utility industry, but we cannot create this without solid foundational principles, which are as follows:

- financially viable utilities are essential to fund and support an enhanced electric grid;
- policymakers must promote clear policy goals as part of a comprehensive, integrated jurisdictional energy policy or 21st Century Utility model;
- a commitment to engaging and empowering customers can help them make intelligent energy choices, including third-party engagement and access to necessary data; and
- equitable tariff structures promote fairness and policy goals.

Financial Viability

Enhancing our electric grid to achieve our reliability objectives will require significant investment. The Brattle Group estimated that $75 to $100 billion per year (in 2009 dollars) will be required to maintain reliability levels. The industry, however, has operating income of $30 billion per year before paying dividends, which means it needs access to external capital to raise the significant funds (in excess of $50 billion per year) to support the existing business and make the required future investments. Accessing capital of this magnitude requires investment-grade credit ratings (BBB- or above, using Standard and Poor's parlance). The better the financial health of the utility, the larger its potential audience for capital and the lower the cost of capital realized. Thus, financially healthy utilities are a key foundational component of a 21st Century Utility model. Importantly, financial health is built over many years of experiencing a transparent and durable operating environment, with consistent policies and financial performance.

Clear Policy Goals

The utility industry cannot evolve without rules and regulations that support the desired evolution. Thus, policymakers must assess the landscape and create, through active interaction with key stakeholders, clear policy goals and a program to achieve them. Each jurisdiction will need to fully explore the interests of stakeholders, the policy objectives already in place and the impacts of proposed policy shifts on their stakeholders. The objective is to develop a comprehensive and integrated set of policies that drive toward the desired outcomes while accounting for constraints to reaching the vision. Although several states are exploring the opportunity to refine their utility model (see **Experiences in Selected States and the UK**, page 25), no state to date has implemented an integrated, comprehensive set of policies, with a timeframe and plan to reach an objective. Without a comprehensive set of policies and a plan, a jurisdiction may have a variety of programs, some mandated and others aspirational, to refine utility services. But such plans require appropriate incentives and accountability as a comprehensive package to drive reform.

Customer Empowerment

A commitment to empowering customers to make intelligent energy choices may seem obvious, but it requires proper alignment of stakeholder interests. Traditionally, utilities have been motivated to sell electricity, not support reduced consumption or investment. We need to remove the model bias that promotes traditional utility financial value and create an environment in which all stakeholders are aligned and benefit from behaviors consistent with the vision. When shared interests are recognized, we have an opening for an environment that supports customer value creation, including promoting actions and tools for customers.

Equitable Tariff Design

Utility tariff structures will be a key component of the strategy to achieve a 21st Century Utility. Tariffs are central to both customer value decisions and recovery of revenues to support utility financial health. The development of tariff structures that support policy-driven objectives and that are fair to all customer classes is a key area of debate. In a model that focuses on efficiency and cost of service, inclining block rates have been a favored tool to mitigate excessive energy use. The problem for utility revenues is that this rate structure feeds customer choice dynamics that reward DER selection and transfers costs to non-DER customers. In the discussion of tariffs that follows, a package of solutions is proposed that is intended to encourage policy goals, fairness to all customer classes, systemwide cost optimization and utility financial stability.

Planning to Accelerate and Coordinate Industry Evolution

The U.S. has more than 50 state/district regulatory authorities overseeing investor-owned utilities, which represent over 70 percent of the U.S. electric industry.[17] To enable the industry to evolve, states have generally taken the approach of setting goals (e.g., RPS) and programs but rely on utility mandates or the competitive marketplace to innovate and provide solutions directly to customers, with the expectation or hope that customers will engage in these products and efficiency behaviors. If we rely on the marketplace to support the future of electric services, the most successful competitive market participants will win, but they may not be the most efficient for customers or society overall, as evidenced by the relatively low penetration of and energy savings from efficiency technologies.

To drive our electric energy future so as to optimize our finite resources (energy and capital), it seems appropriate for policymakers to proactively develop a comprehensive vision and plan for each jurisdiction's energy future. The objective would be for us to take charge of our direction and accelerate the efficiency of activity, and thus mitigate any waste of energy and capital through the transition of the plan to the desired end state. The components of a statewide energy or 21st Century Utility plan would include:

- **vision**—how we expect customers to use and manage their electricity needs in the future;
- **objectives**—comprehensive, integrated policy positions to achieve the vision, including the approach to deploying renewables, storage, DER and microgrids;
- **defined goals**—providing metrics and timeframes for achieving progress toward the realization of the vision;
- **clear participant roles**—who will be held accountable for driving the vision, and how customers, policymakers, utilities and competitive service providers will interface and cooperate;
- **incentives**—quantifying the appropriate level and approach to allocating financial incentives to stakeholders to accelerate and realize the vision;
- **accountability**—ensuring the realization of the vision through metrics, incentives and penalties; and
- **feedback loop**—how often the plan will be evaluated to reflect changing market dynamics and opportunities.

Given their scale, presence and interaction with all stakeholders, particularly customers, utilities appear to be the only logical entity to coordinate and be held accountable for the execution of a 21st Century Utility model and the realization of milestone goals.

Essential to the evolution and acceleration of a 21st Century Utility is the education of customers on the opportunities and benefits of optimizing their energy use (reducing use and/or moving load off-peak), deploying alternative technologies to optimize usage and offering assistance in adopting such new services. The more effective the education and ease of effort to adopt and utilize new services, the more likely that customers will be receptive.

While utilities have offered energy-efficiency programs and services for years, the Internet and smartphones are accelerating customer education and energy optimization. Smartphone apps turn what used to be low-priority chores into fun ways to be productive and share success and opportunities with friends. So although utilities have been involved with efficiency in the past, technology is driving exciting new products and services, and smartphone deployment is making it easier to adopt and manage these new technologies.

17 EEI, EEI website.

The Clean Power Plan

The EPA's newly issued CPP offers states an excellent opportunity to develop their energy strategies for achieving a 21st Century Utility business model. Issued in August 2015, the long-awaited rule governs performance standards for greenhouse gas emissions from existing and new power-generation sources. The CPP outlines the first national standards for CO2 emissions from power plants and seeks to reduce emissions from the power sector by 32 percent in 2030 from 2005 levels. Among its benefits, the CPP aims to improve health by reducing pollutants, supports clean-energy innovation and provides the foundation for a national climate change strategy. Compliance commences by 2022, with phase-in completed by 2030.

While lawsuits have already been filed against the rule, when implemented the CPP will be based on three building blocks: (i) improved performance of existing coal-fired power plants, (ii) substitution of natural gas power generation for coal-fired capacity; and (iii) increased renewable generation to an estimated 28 percent of our energy mix by 2030.

Each state is responsible for developing and implementing a plan that ensures compliance through the phase-in. States have the option to implement plant-specific performance plans or a statewide portfolio approach. While end-user energy efficiency is not a formal building block in the rule, it is allowed as a compliance option. States can also join together to develop multistate solutions, such as the Regional Greenhouse Gas Initiative. The rule calls for state plans to be filed by September 2016, with the potential to seek extension until September 2018.

While the CPP provides significant flexibility to states, the rule will likely lead to reduced coal-fired power generation and a significant expansion of renewables to achieve the targeted CO2 emission reductions. For renewable power generation to grow from 13 percent of our power mix in 2013 to 28 percent in 2030 will require a dramatic increase in renewable-energy capacity and investment.

States will likely consider multiple strategies to encourage an increase in renewable energy, including expansion of RPS mandates to support their CPP implementation plans. Based on projections developed from Energy Information Administration (EIA) data, the renewable capacity required to generate the 2030 goal could stimulate up to 350GW of incremental renewable capacity. This level of capacity expansion will require all forms of renewables to be adopted, but utility-scale renewables will likely be a very large component of the compliance requirement, given their scaling potential and economic advantages.

The timeframe set for state CPP compliance plans provides an excellent opportunity for each state to develop its energy strategy in alignment with the 21st Century Utility model proposed in this paper.

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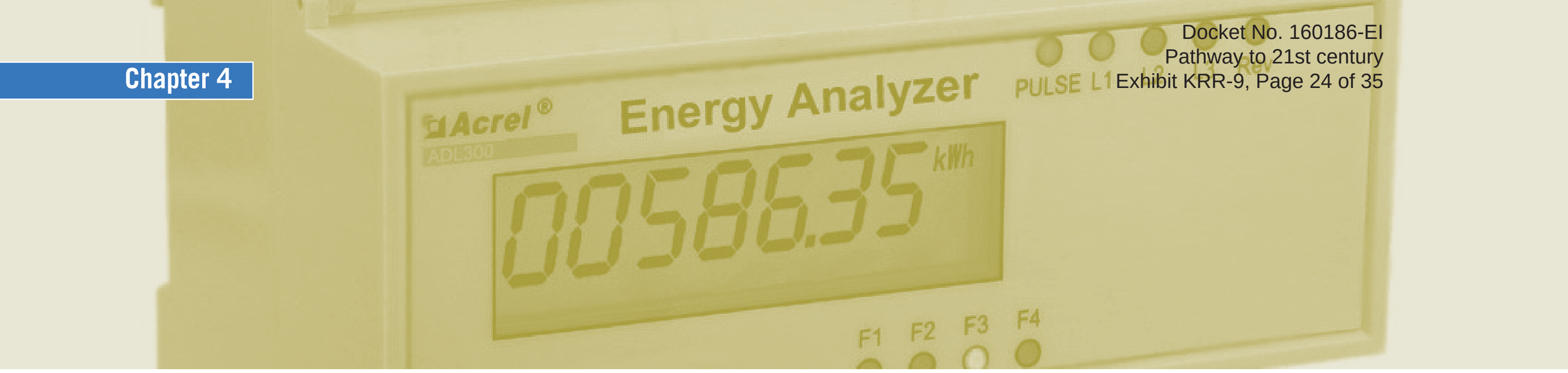


The Pathway to a 21st Century Electric Utility

Stakeholders will likely agree on the vision and foundational principles to support a 21st Century Utility model, but the way to achieve it will be more heavily debated. This paper introduces a pathway for accelerating the realization of a 21st Century Utility by setting clear policy direction, assigning accountability for results and shifting the focus of regulatory oversight from litigated rate proceedings to forward planning and accountability with incentives and penalties. The following pathway points are not an á la carte menu of choices but are intended to be a combined package of actions to support and integrate realization of the vision.

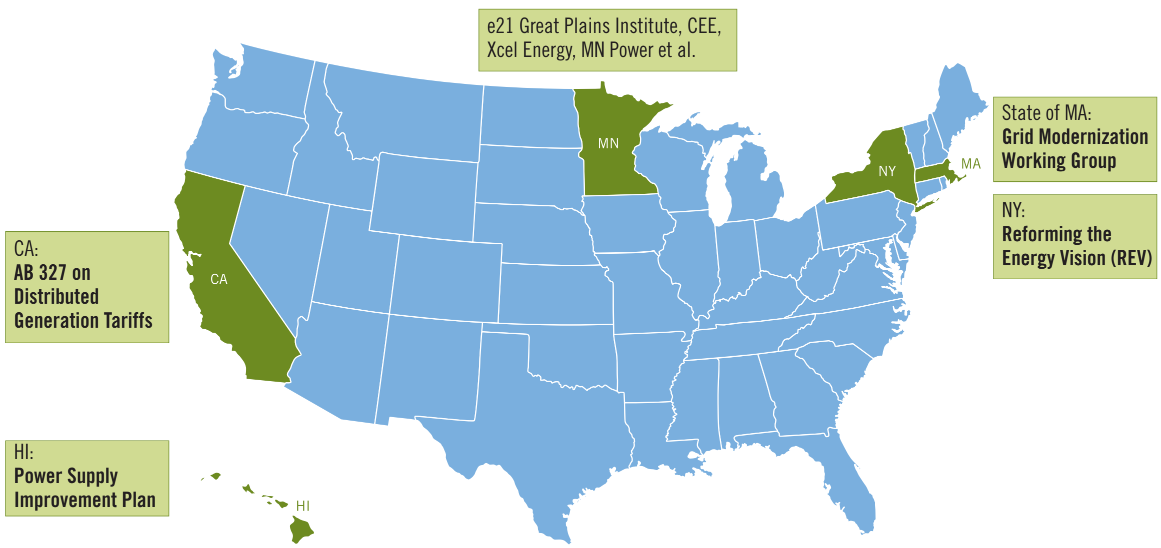
- State policymakers pursue legislation to outline the model for a 21st Century Utility, to include:
  - providing environmental, RPS, energy-efficiency, demand response and peak-load management objectives, including transitional targets;
  - refining building standards to address new construction and major modifications to support efficiency and environmental footprint goals (e.g., California Zero Net Energy Plan for new construction);
  - accountability metrics for managing the transition to the vision;
  - reform of the regulatory oversight approach to focus on planning and accountability oversight; and
  - outlining the role by which distribution utilities will be authorized to participate, including the potential for service revenue and behind-the-meter asset ownership.
- Regulatory reform is enacted to support efficient resource deployment and accountability:
  - multiyear integrated transmission and distribution system planning process, including defining the value and cost-effectiveness of renewable options;
  - transparent and sustainable accountability metrics to be set, based on customer and policymaker objectives;
  - transparent and sustainable incentives (and penalties) for accountability as to realization of policy objectives;
  - multiyear rate proceedings to target customer focus and shift of resources from regulatory administrative proceedings to planning and results accountability; and
  - structure of utility revenue potential for integrating new customer services and potential for ownership of DERs, including revenue requirement implications.
- Tariff structures are refined to support price signals and financial viability requirements, including:
  - inclining block rates to encourage efficiency and signal incremental cost of new resources;
  - bidirectional meters installed for all DER customers;
  - transition to highest economic value renewable rate:
    - most economical option to meet RPS, adjusted for transmission and distribution investment, line losses, system reliability and emissions avoidance value, and
    - timing of transition and grandfathering of existing DERs;
  - demand response to be bid into capacity planning to encourage load resource optimization; and
  - time-of-use rates to be implemented to manage peaks and enhance system optimization.
- Utilities are empowered and accountable for managing the transition, and are:
  - held accountable for controllable results in achieving a 21st Century Utility;
  - encouraged to lead the integration of new technologies and given incentives to achieve results, as deemed appropriate;
  - responsible for educating customers on new energy management alternatives; and
  - the potential owners of renewables, new technologies, or DERs, as addressed in statewide energy or 21st Century Utility plans.

Experiences in Selected States and the UK

States with high electric prices, locational DER opportunities or grid reliability challenges will likely take the lead in pursuing 21st Century Utility proceedings and, hopefully, implementation programs. Clearly, states will develop policies and strategies that reflect their unique circumstances regarding policy, system resource issues, locational opportunities and energy costs. Many states will learn from first-mover jurisdictions that are pursuing a 21st Century Utility model in a comprehensive manner.

While practically every state has addressed specific issues related to energy supply and efficiency programs, few have developed a comprehensive framework for engaging the utility of the future. California and New York have been the most proactive in leading change in their markets. Also worthy of note is the Revenue = Incentives + Innovation + Outputs (RIIO) model in the UK and how it has addressed the alignment of customer, policymaker and utility interests. In Minnesota, policy advocacy and utility interests have proposed an interesting paradigm to develop the electric utility model and are in the process of collaborating with state policymakers to discuss the proposed framework, referred to as the e21 Initiative.

Figure 9: Responses to Evolving Electric Utility Models



Source: Great Plains Institute, July 2015.

California has led efforts to reform its utility model, dating back to an aggressive Public Utilities Regulatory Policy Act implementation program in the 1980s and its groundbreaking 1994 industry-restructuring docket. However, the California energy crisis of the summer of 2002 illustrated that not all that has been tried in California has met with success. Still, California has led with its aggressive implementation of renewables through its RPS (now seeking a 50 percent renewable mix by 2030), attracting both rooftop and utility-scale renewables, and energy-efficiency spending (about 30 percent of U.S. spending).[18] California also leads on incentive programs for utilities to achieve efficiency savings and programs to enhance energy-storage technologies, though the incentives for efficiency adoption are modest relative to the amount needed to drive significant organizational focus and strategy.

Currently, California is mandating that distribution resource plans be provided by each utility, with a focus on better integrating DERs into the grid. However, California has not gathered its array of programs into a comprehensive 21st Century Utility model, and is only beginning to unleash the full power of its nearly statewide advanced metering infrastructure, including meaningful residential customer application of time-of-use rates. Policymakers are facilitating change through mandates, due to California's high electric prices and their willingness to allow cross-subsidies among and between customer classes. Such mandates raise questions as to the fairness of benefits to all customers, given the small but growing percentage of customers who take advantage of market opportunities, such as rooftop solar rewarded with high net energy metering buy-back rates.

18 Edison Foundation Institute for Electric Innovation, "Summary of Electric Utility Customer-Funded Energy Efficiency Savings, Expenditures and Budgets", (2014).

New York has been the most active in pursuing a comprehensive solution to a reformed utility model. The New York state proceeding Reforming our Energy Vision (REV) intends to promote more efficient use of energy, including increased penetration of renewables and DERs. It also intends to promote markets to drive greater use of new technologies for energy management. The objective is to empower customers by providing more choices for managing their electric consumption. Utilities, under REV, will be tasked with operating the grid and acting as the distribution-service platform provider, integrating market solutions into the grid. The New York Public Service Commission (NYPSC) is considering tariffs and incentives to better align utility interests with achieving the commission's policy objectives. The Staff of the Department of Public Service issued a white paper[19] in July 2015 proposing future incentive opportunities for New York utilities, including market-based earning opportunities from new grid-related services and incentive mechanisms for performance consistent with goals. The REV initiative is a work in progress.

Neither California nor New York has yet created material, timely or transparent incentive frameworks to move utilities to revise their approach to customer engagement, or otherwise taken a leadership position to encourage large percentages of the customer base to more proactively optimize energy consumption. In New York, that is starting to change. Con Ed's BQDM Program, discussed earlier, is a recent example of the NYPSC approving an innovative solution that does provide for incentives to the utility.

If the system can benefit from efficiencies related to operating versus capital expenditures, the utility will earn a return on a component of such efficiency savings while the customer benefits from a lower cost.

In California, the incentives available two years after the reporting period yield less than 1.25 percent of utilities' operating income.[20] This level of incentive does not motivate major corporate strategic reassessment of operational, financial and compensation strategies. In addition, the programs in California and New York do not promote the most efficient use of DERs, but encourage the marketplace to adopt DERs, at the same time discouraging the utilities from investing in them by offering attractive net energy metering incentives.

Minnesota's e21 Initiative is an interesting and important collaborative effort to develop Minnesota's 21st Century Utility. The effort is led by the Great Plains Institute, an energy policy advocacy group, and involves Minnesota's investor-owned electric utilities and several national energy policy groups. The initiative proposes a comprehensive framework for a 21st Century Utility and regulatory oversight approach. The Phase I report, issued in December 2014, includes the following recommendations:

- reward utilities for delivering customer value with reduced reliance on a capital investment–driven model;
- align the utility model with state and federal policy goals;
- enable the delivery of services that customers value;
- fairly value grid and DER services;
- focus on economic and operational efficiency of the entire system;
- reduce regulatory oversight–related administrative costs; and
- facilitate innovation and implementation of new technologies.

e21 proposes performance-based ratemaking as an incentive to utility performance, consistent with multiyear integrated system plans that focus on DER deployment and reducing costs through system wide efficiency measures. The initiative seeks to establish multiyear rate programs to shift the regulatory oversight focus from rate-case preparation and deliberation to forward planning.

The e21 Initiative, while in its early stages, represents a comprehensive and collaborative approach to pursuing a 21st Century Utility model. Unlike New York's REV, this initiative is more robust in that it provides a larger role for utilities to engage with customers and it outlines how regulatory oversight should evolve. For the initiative to move forward, policymakers will need to endorse the framework outlined. How this initiative is ultimately received by Minnesota policymakers, and the full range of public process participants that engage in the discussion, will shed light on the prospects for policy-led collaboration toward a new utility model, in Minnesota and nationally.

The **United Kingdom's RIIO** model is encouraging to consider for its impact on ratemaking solutions. The RIIO model builds on the UK's prior approach to determining revenue. It will create eight-year periods for price review, under which utilities have the opportunity to realize operational efficiencies, subject to accountability metrics, and given incentives to consider operating investments that replace or defer capital investment (known as Totex, or total expenditures). Totex was structured to address the inherent utility bias toward capital investment (rate base) by capitalizing and allowing a return on, and of, investment of certain operating expenditures that avoid or defer less economical capital investment. The concept is to focus on optimizing total system expenditures. If the system can benefit from efficiencies related to operating versus capital expenditures, the utility will earn a return on a component

19 State of New York Department of Public Service, "Staff White Paper on Ratemaking and Utility Business Models," July 28, 2015

20 SEC Form 10-K for Edison International and PG&E Corporation

of such efficiency savings while the customer benefits from a lower cost. The criticism of RIIO is that significant regulatory proceedings, costs and ongoing oversight are required to approve and execute on a RIIO planning period. So, while the RIIO model may not be appropriate for many U.S. states due to the significant administrative burdens created for policymakers and utilities, components of RIIO, such as multiyear regulatory review periods and Totex, are worthy of consideration for implementation.

Developing an Accountability and Incentive Framework

The utility model we operate within today is highly regulated and mostly backward looking in its approach to regulation. In an ideal world, policymakers would outline their policies and develop accountability metrics to monitor and evaluate utility performance. Instead of mandating and overseeing countless proceedings as to utility performance, a strategy could be employed by which reasonable accountability metrics were tied to meaningful incentives and penalties that would lead utilities to focus on achieving best-in-class performance. Since U.S. utilities for the most part already provide best-in-class reliability of service, new accountability metrics would focus on achieving performance toward a 21st Century Utility framework. Examples of potential accountability metrics, focusing on customer and policy goal realization and the transparency and sustainability of such goals, are as follows:

- **reliability**—percentage of hours of uninterrupted electric service and percentage and number of annual outages impacting customers;
- **service**—range of customer energy solutions offered, number of customer calls, call wait times and number of calls to resolve complaints;
- **efficiency**—weather-adjusted decline in energy usage due to efficiency adoption and peak load management and optimization;
- **clean energy mix**—increase in renewables and DERs and decline in carbon footprint relative to RPS standard transitional goals; and
- **investment**—capital and total spending below a predetermined rate, subject to carve-out for critical infrastructure investments.

To be effective in driving change, incentives and penalties must be transparent (i.e., easy to understand, calculate and report on in a timely manner). To drive and align behavior change, significant opportunity and dollars should be at risk for achieving on incentive performance, for example up to 10 to 20 percent of profits. A utility realizing a 10 percent ROE would be able to earn up to 12 percent for meeting its incentive targets. While there is no science behind that incentive number, it must be meaningful to encourage changes in behavior, and less than 10 percent is unlikely to achieve that goal. In order to encourage the behavior and innovative spirit that are essential to achieving continuous performance improvement, incentives must be durable. They must be available and achievable on an ongoing basis and subject to revisions as market conditions evolve. For capital markets to differentiate between those states that provide incentives and those that do not, durability will be an important component.

The benefit of a multiyear regulatory plan is that utilities can align their strategy with the implementation of their integrated distribution plan, which will free up resources that can be deployed in effective future planning because fewer resources will be required to process rate cases. Transparent accountability metrics and resulting incentives and penalties will provide ongoing oversight of utility performance and progress in reforming our energy future. Policymakers, through their regulatory oversight, can ensure that the integrated system plan responds to their stated objectives. In particular, agreement can be solidified on deploying and valuing renewables, such as community solar and rooftop solar. A robust integrated system plan would provide utilities with an effective roadmap for operating over the planning period with improved clarity as to the path of utility rates over that period. Each new integrated planning cycle would provide an opportunity to refine the next plan, so as to continuously improve the process and respond to customer and marketplace dynamics.

The utility would not be responsible for developing new technology, but for assessing and working with technology providers to bring best-in-class technologies to the customer base.

Engaging Utilities to Adopt a 21st Century Electric Utility Model

The pathway proposed in this paper looks to the utility as the facilitator, integrator and nonexclusive distribution channel to offer new products and services to its market. The utility would **not** be responsible for developing new technology, but for assessing and working with technology providers to bring best-in-class technologies to the customer base. With the support of policymakers, utilities may be allowed to own and operate (either through the regulated entity or an unregulated affiliate) assets behind the meter, or at a minimum, could leverage competitive providers to offer the best price to customers. The advantage of utility ownership is scale and cost of capital benefits.

The following summarizes why utilities should be at the forefront of leading, integrating and accelerating the transition to a 21st Century Electric Utility, from the perspective of key stakeholder interests.

Benefits to Customers

- high level of recognized trust in utility providers versus a large group of unknown vendors of competitive energy services and technologies (including efficiency, demand response, load management and DER providers);
- access to customer and electric system information that supports a program for system optimization regarding future investment (subject to strong standards to protect consumer privacy);
- increased quality control oversight of third-party competitive energy service providers and products, given their scale, system knowledge, resources and lack of incentive to promote one new technology over another;
- enhanced information analytics based on customer usage experience to support customer decision making regarding innovative energy-optimization product alternatives; and
- lowest systemwide cost of deploying optimal located investments with scale technologies.

Benefits to Policymakers

- acceleration of defined policy objectives (efficiency, system optimization, environmental) through properly structured incentives and accountability for realizing results;
- ability to enhance accountability via regulatory oversight of utilities; and
- opportunity to mitigate the level of utility rate increases required by allowing utilities to earn additional revenues related to facilitating, integrating or owning new services, including behind-the-meter assets.

Benefits to Competitive Marketplace Service Providers

- endorsement of best-in-class providers and technologies;
- partnering with utilities can facilitate increased adoption of new value-add technologies; and
- partnering with utilities can reduce customer acquisition costs and thus enhance profitability (through reduced cost and increased volumes).

Benefits to Utilities

- enhanced customer service by increasing interactions with customers;
- optimized investment and reduce costs and risks;
- enhanced regional economic growth through enhanced optimization of utility system and services;
- enhanced citizenship profile;
- potential to earn incentives for achieving accountability goals; and
- ability to earn additional revenues from participating in facilitating and integrating realization of a 21st Century Utility, thereby creating potential to offset rate-increase needs and earn incremental returns for investors.

Those opposed to utilities owning behind-the-meter assets within the regulated business fear that it could: (i) complicate the regulatory model and ratemaking, (ii) increase potential financial risk to customers for un-creditworthy decisions and (iii) freeze out competitive industry players. Policymakers/stakeholders would have to evaluate these issues when considering whether and how to allow utilities or utility-affiliated entities to participate in behind-the-meter infrastructure.

We now have an array of competitive entities seeking to offer new electricity products and services to both residential and large commercial and industrial customers. This is a positive development, but there is little, if any, oversight of the quality of the services offered, including the economic efficiency of these new inputs to the energy delivery system. Third-party entities partnering with utilities should create the right type of checks and balances by which utilities can oversee the development of new technologies that impact their system, invest as appropriate to support the grid needs and enable best-in-class technologies, and act as a distribution channel to assist in deploying new technologies. However, competitive service providers may seek utility system data to support their initiatives, and policymakers will need to resolve issues regarding data control, sharing and privacy protection.

Regulators in this paradigm would be able to drive utility accountability through appropriate and transparent customer and policy performance standards, consistent with the objectives of economic provision of reliable, clean and affordable energy services. In addition, regulators would determine how utilities would be compensated for their role in facilitating change and customer adoption through incentives, as well as penalties when performance standards are not met. They could further offer commissions for utilities facilitating sales of new products offered by vendors, and structure compensation and returns allowed on utility (or utility affiliate) ownership to allow for behind-the-meter assets.

Utilities have been timid in claiming a role in accelerating and executing a 21st Century Utility model. Several factors have likely caused a less than aggressive posture: skepticism on the part of regulators, who often suspect that utilities may earn outsized profits from future activities and, thus, have sought to encourage the competitive marketplace **without** providing rules for how utilities can participate; a strong lobbying effort by competitive market providers to prevent utilities from participating in new services; and utility compensation programs aligned with fiduciary duties that do not encourage development of new markets but focus on reliability and near-term financial performance.

Vertically Integrated vs. Restructured Utilities

Given the restructuring of U.S. electric utility markets and utilities' roles in 17 jurisdictions during the 1990–2005 period, the industry is no longer a homogeneous group of vertically integrated (distribution, transmission and generation) utilities. In most restructured markets, distribution utilities own no meaningful level of power generation and thus are less exposed to threats to the economics (and value) of the power markets. The volatility and profitability of power generation in restructured markets is borne by competitive generation companies (whether independent from utility ownership or in unregulated utility-affiliate entities). However, to the extent utilities in restructured markets collect tariffs based on energy usage, these transmission and distribution utilities remain exposed to fluctuations in customer energy usage. Thus, not all utilities will be impacted by the same set of factors in the transition to a 21st Century Utility sector.

Importantly, the highest-cost markets that are seeing the most interest in efficiency and new technologies tend to be in restructured regions. Thus, we expect that these markets will tend to be at the forefront of driving industry change.

Because vertically integrated utilities own power generation, they are more exposed than transmission ad distribution utilities to the electricity consumption impacts of DERs and various forms of energy efficiency. Declining consumption for these companies results in lower revenues to recover generation investment and the related adverse impact on market power prices (due to lower demand and increasing supply from DERs). Thus, all other factors aside, it is likely that electric generation owners, including vertically integrated utilities and competitive generators, will be less interested in moving toward a 21st Century Utility until the level of unrecovered investment in power-generation assets becomes less meaningful. This does not suggest that a transition may not occur prior to recovering greater levels of generation investment, since regulators can approve structures, such as transition charges, to accelerate change if they deem it appropriate. In fact, the e21 Initiative was developed for adoption in Minnesota, which is a vertically integrated utility market.

Utilities in restructured states have less at risk in moving forward with a 21st Century Utility sector. While these utilities may still be exposed to kWh consumption-based tariffs, the impact can be more easily managed by decoupling or other mechanisms to mitigate any drag on return on invested capital. Importantly, the highest-cost markets that are seeing the most interest in efficiency and new technologies tend to be in restructured regions. Thus, we expect that these markets will tend to be at the forefront of driving industry change.

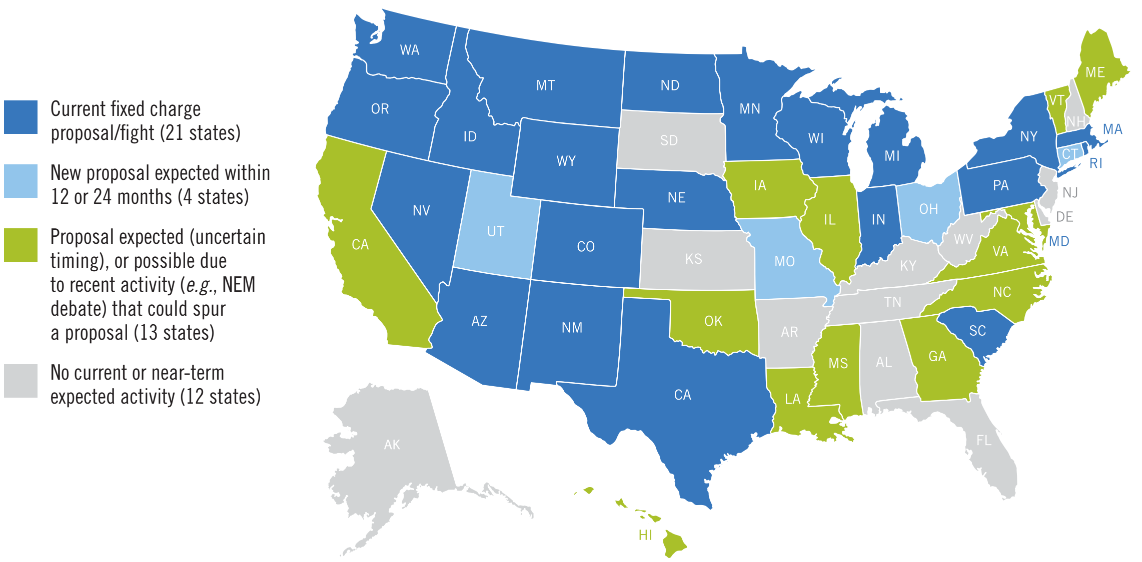
Ratemaking and Tariff Design

Important components of the evolution to a 21st Century Utility industry model are the topics of ratemaking and tariff design. For purposes of this paper, ratemaking is defined as the process by which regulators determine the appropriate aggregate annual revenue collection (or revenue requirement) utilities may recover from customers to cover costs and earn a fair return on invested capital. Tariff design refers to the structure of customer rates (or prices charged) to recover the revenue requirement allowed.

Ratemaking, which is grounded in legal precedent as to the utilities' right to recover prudent costs, is not a hotly contested issue in the 21st Century Utility debate. The ratemaking discussion has often focused on structuring a system whereby utilities have no incentive for (or are indifferent to) increased capital investment (aka rate base) to provide service, such as in the UK's RIIO model.

Tariff design is the tool that regulators use to promote policy objectives, such as equitable distribution of cost, customer usage and consumption behavior. "Disruptive Challenges" highlighted the confluence of factors challenging the long-term financial viability of our traditional utility regulatory model. The strategies proposed to address and mitigate the disruptive forces outlined were primarily regulatory solutions. Looking through an investor's lens, several tariff-restructuring alternatives were proposed. Those alternatives, which could be implemented individually or in combination, included increasing monthly fixed charges on all customers, monthly service charges for all distributed energy resource (DER) customers and/or

Figure 10: Mandatory Fee Proposals Timing Map



Source: NRDC, NCLC and Vote Solar.

revising the net metering buy-back rate to be based on the wholesale value of the energy provided by the DER customer to the utility (versus the retail rate, as reflected in the majority of net energy metering programs).

Marketplace dynamics since the release of "Disruptive Challenges" suggest that two important factors were missing from that 2013 assessment: (i) the customer and policymaker view that it is not in the best interest of customers or society overall to slow the pace of technology innovation or adoption (a likely result of increased customer fixed charges), and that over the long term, technology advancement cannot be deterred by regulatory rulemaking; and (ii) customer and policymaker actions through 2015 that have demonstrated a clear policy opposition to meaningful increases in fixed charges, as evidenced by low fixed charges in place throughout the investor-owned utility industry, as well as recent actions in several states that approved nonmaterial fixed charge tariffs (e.g., Arizona Corporation Commission adopting a $5/month charge, not the $50/month charge proposed by Arizona Public Service).

While the cost structure of distribution and transmission of electric utilities is predominantly of a fixed nature (i.e., not meaningfully impacted by volume variability or short-term business issues), utility rate structures have typically authorized a small fixed charge component. Increasing mandatory fixed charges (or demand charges), a solution proposed in *"Disruptive Challenges,"* is a tariff design tool that utilities have actively pursued since 2013 to mitigate revenue risk from disruptive forces. According to the Environmental Law and Policy Center, **24 utilities have recently proposed increases to their fixed fees**.[21] However, significant increases have met with strong opposition from customer interests and policymakers.

Adopting meaningful monthly fixed or demand charges system-wide will reduce financial risk for utility revenue collections for the immediate future, but this approach has several flaws that need to be considered when assessing alternatives through a win4 lens, by which all principal stakeholders benefit. Fixed charges:

Adopting meaningful monthly fixed or demand charges system-wide will reduce financial risk for utility revenue collections for the immediate future, but this approach has several flaws that need to be considered when assessing alternatives through a win4 lens, by which all principal stakeholders benefit.

- do not promote efficiency of energy resource demand and capital investment;
- reduce customer control over energy costs;
- have a negative impact on low- or fixed-income customers; and
- impact all customers when select customers adopt DERs and potentially exit the system altogether, if high fixed charges are approved and the utility's cost of service increases.

While DER customer charges can be structured to reflect

21 Environmental Law and Policy Center Foundation, June 2015.

the value of the grid connection that is maintained by practically all DER customers, such charges will need to consider whether and at what level a DER buy-back rate (the price paid for energy by a utility to a DER supply customer) should be set. Through a win4 lens, it is clear from recent regulatory actions reconfirming support for DERs and net energy metering that policymakers are interested in DER development and customers want the option to choose their own energy supply.

It is therefore in the long-term best interests of utilities to support such choice, consistent with regulatory policies that support financial viability and avoid meaningful monthly fixed charges. By instituting monthly DER customer grid fees or reducing buy-back rates, it is likely that rooftop solar activity will be slowed, and this must be considered in the policy debate. This is consistent with the early experience of the Salt River Project (SRP), which is not regulated by the Arizona Corporation Commission and implemented a $50/month renewable customer grid charge for all new rooftop installations. Since that announcement, one major rooftop supplier reported a 96 percent decline in new solar applications in the SRP territory.

Besides the installed cost advantage of utility-scale solar versus rooftop solar and system optimization considerations, community or utility-scale solar brings the advantage of renewables to all customers without the potential cross-subsidy issues associated with rooftop solar.

Given the new tools available to enhance system wide efficiency, including peak load management, time-of-use rates can be an important tool in managing a dynamic optimization of resources as market demand and supply evolve in a technology-enhanced 21st Century Utility model.

Tariff Design Principles for a 21st Century Electric Utility

As we consider fairness to all customers, we should provide incentives to fund the most cost effective renewable options. In October 2015, the Hawaii PUC halted its net energy metering program for new systems due to penetration in excess of 20 percent. This is the first significant action to slow the growth of rooftop solar penetration due to the high cost that NEM programs shift to non-DER customers. In a recent study prepared by the Brattle Group entitled, "Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area," the findings demonstrate that "utility-scale PV system is significantly more cost-effective than residential-scale PV systems when considered as a vehicle for achieving the economic and policy benefits commonly associated with PV solar. If, as the study shows, there are meaningful cost differentials between residential and utility-scale systems, it is important to recognize these differences, particularly if utilities and their regulators are looking to maximize the benefits of procuring solar capacity at the lowest overall system costs."[22]

Given the significant net cost benefit of approximately 45 percent for utility-scale solar (due to capacity costs and power output optimization), pricing of rooftop solar and related subsidies, and other energy technology alternatives, should be determined by the most efficient alternative opportunity, after factoring in grid-related costs and benefits. Tariff fairness can be structured, such as by adopting renewable grid charges or adjusting DER buy-back rates (i.e., net metering), in a way that factors in the economic value of adding renewables to the grid and creates an opportunity for all customers to benefit equally from the adoption of renewables, not just homeowners who can deploy solar on their rooftops.

Without increased demand for electricity sales, fixed charges to all customers, or DER grid charges, utilities will continue to be exposed to customer switching and under recovery of revenues. This is especially true for utilities with inclining block tariffs (i.e., the more you use, the higher the rate for incremental energy consumed) that are in excess of the cost of DER alternatives. The result of ongoing customer adoption of DERs in net energy metering states (43 of 50) is that future rate increases are required to offset the revenue lost from those customers adopting DERs. This scenario feeds a cycle of customer adoption of DERs and eventually results in increasing rates for non-DER customers. The advent of (i) bidirectional metering, (ii) most economical value of renewable buy-back rates and (iii) revenue-decoupling mechanisms can assist in mitigating this risk.

Time-of-use (or real-time) pricing has the potential to be an important tool in optimizing system capacity and moderating incremental capital investment in electric energy infrastructure. While this type of tariff design has been discussed for years and is supported by smart-meter technology investment, policymakers have generally not supported it. The lack of support from policymakers is a roadblock to moving forward on a 21st Century Utility model.

Time-of-use rates have not been widely implemented due to technical constraints—a lack of smart-meter

22 The Brattle Group, "Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area," Prepared for First Solar, July 2015.

infrastructure—and a lack of public interest. Customer concerns include lack of understanding, potential volatility of bills, and impact on low- and fixed-income customers. Given the new tools available to enhance system wide efficiency, including peak load management, time-of-use rates can be an important tool in managing a dynamic optimization of resources as market demand and supply evolve in a technology-enhanced 21st Century Utility model. Thus, we need to expand our efforts to educate and pilot these programs. While "opt-in" programs have often realized low adoption levels, another alternative to consider is selected "opt-out" programs, where appropriate, to encourage realization of policy objectives.

Factoring in financial viability considerations and customer and policy preferences, the following tariff principles are components of a tariff design that can contribute to the development of a 21st Century Utility model:

- introducing inclining block rates to promote efficiency of energy consumption;
- decoupling of revenues from volumetric usage charges to protect cost-recovery shortfalls in the short-term, for example due to customers switching to DERs or declining usage due to new technologies; however, decoupling does not reduce the long-term vicious cycle of increasing customer adoption of DERs created by increasing rates;
- providing bidirectional meters to all DER customers so that energy consumed from utilities would be charged based on utility tariff schedules, and buy-back rates for DER-produced energy at a value of renewable rates;
- setting the value of renewable rates at the higher of competitive wholesale energy prices or the levelized cost of the lowest incremental cost to deploy efficient renewables (e.g., lower of rooftop vs. utility scale, with adjustments based on evaluation of system costs and benefits); and
- establishing time-of-use rates to optimize system efficiency; time-of-use rates will enhance the value of new technology investment as customers optimize the value of this rate structure (e.g., using appliances with time-of-use controls).

With these principles in place, tariff economists can fine-tune potential tariff structures to support a 21st Century Utility model. Each jurisdiction will have its own unique issues and cost structures that will impact the ideal approach in its market. Since we are likely to grandfather existing DER customers during the transition period, we should address the tariff issue now to define the ultimate transition period, provide fairness to all customers and mitigate financial risk to customers and utility investors.

Financial Issues

The financial health of utilities has improved over the last several years, based on the support of regulators for allowing recovery of revenue shortfalls due to declining consumption and customer growth, with increased use of decoupling of revenues from consumption in some form now in over 28 jurisdictions. In addition, a decline in the cost of fuel to generate power, lower merchant power prices and lower interest rates have provided additional headroom for base utility rate increases. In this environment, and reflecting lower interest rates in the financial markets, utility credit ratings have stabilized from the continuous decline experienced from the 1960s through 2010, and utility equity prices have been at or near all-time highs on a dollar price and multiples-of-earnings basis. Investors are generally pleased with the utility sector's performance, and likely hope the current business model prevails for the foreseeable future. Unfortunately, hope is not a strategy.

However, below the surface, lie foundational shifts that suggest the steady period of utility performance will be challenged by customer choice, the adoption of new customer-driven technologies and customer behavior changes driven by social and economic forces

However, below the surface, as described in countless industry trade articles and in "Disruptive Challenges," lie foundational shifts that suggest the steady period of utility performance will be challenged by customer choice, the adoption of new customer-driven technologies (e.g., Nest) and customer behavior changes driven by social and economic forces (e.g., smaller homes). Investors have shown from prior experiences in other industries that they become noticeably concerned about disruptive challenges when the loss of sales and revenues is reflected in financial results. For utilities, this can happen when serious rate-increase opposition accelerates due to the impact of increasing penetration of DER technologies.

Although these disruptive challenges are well outlined in utilities' SEC filings, utility managements are managing their businesses based on the current framework and their fiduciary duty to focus on quality service for customers and growth in near-term earnings and investment value for investors. As long as investment spending supports growth through increased rate needs, the problems lurking in the future are kicked down the road, although one could argue that the problems are amplified by increasing utility rates in the short term. In addition, utility management compensation is focused on near-term reliability and financial goals, creating a fiduciary obligation and compensation incentive for management to focus on the near term.

For the time being, all may appear well, but if one believes that risks are at play, when these threats become a financially reality, investment values will be impacted. Capital availability will decline as investors focus on the potential for declining profitability and the risk of stranded assets or cost levels that the remaining customer base may be unwilling to bear. Given the importance of utility access to capital to support the grid, this is not an acceptable scenario.

The objective is not to create fear or call for a death spiral, but to commence the transition now to a future that customers support and in which utilities can play a constructive role and access the capital required to build this future. As a point of reference, who would have thought that essential service industries in a growing economy such as the airlines and the landline phone business would not support investment-grade quality ratings as stand-alone entities?

The New 21st Century Electric Utility

The current transition of the electric utility framework into a new model is being led by economic and technological forces that will ultimately drive change. This is particularly true given the support of policymakers for customer choice of electric supply and new technologies to drive efficiency, system optimization and the reduction of our environmental footprint through expanding our mix of clean energy sources.

The actions by states to date in considering meaningful regulatory change have been predominantly in support of a free marketplace for competitive providers to offer their new services to customers directly or through utility-run efficiency programs. In that environment, the utility is relegated to grid provider, and policymakers have few levers to oversee or influence the marketplace to achieve their vision.

The environment that this paper proposes is one in which the utility is responsible for the development and operation of the grid, but is also encouraged and accountable for accelerating our progress toward a 21st Century Utility model. The utility will be encouraged and accountable for promoting the adoption of new technologies, and for developing a cost-effective plan to deploy technology in the most efficient way to control customer costs. In this scenario, cost of capital on new investments might consider returns on selected operational spending (similar to the UK Totex model) that mitigates less-than-optimal capital investment. Utilities would also play a traffic cop role by allowing only proven technologies or vendors entry to their application store.

Utility revenues will be determined by regulators to encourage a return on invested capital, particularly for the legacy system in place, and transparent incentives to encourage accountability for accelerating change and policy realization. It may be a challenge to develop tariff mechanisms and incentives, since there exists a distrust of providing utilities an opportunity to increase their returns above currently allowed levels. But common sense and economic theory demonstrate that the best way to achieve results is to provide economic incentives. Regulators will continue to regulate, and thus any midcourse correction deemed necessary can be implemented. The objective is to develop a formula by which customers are served, policy is realized, technology adoption and product offerings by competitive entities is accelerated, and utilities are motivated to achieve the objectives of customers and policy while maintaining financial viability to support the grid.

Concluding Comments: Transitioning to the New Utility Model

The transition to a new industry paradigm will require the proactive support of customers, policymakers and utility regulators, competitive-market service providers, and utilities. In the ideal world this would be a collaborative process, driven by policymakers who understand that the industry model needs to be refined in order to promote the full suite of opportunities that can be created by a 21st Century Utility. A mutual understanding of the benefits of collaboration and economic benefits to all parties is key to a productive process and for defining a clear transition and end state.

Figure 10: The Pathway to a 21st Century Utility Model Vision

Vision:

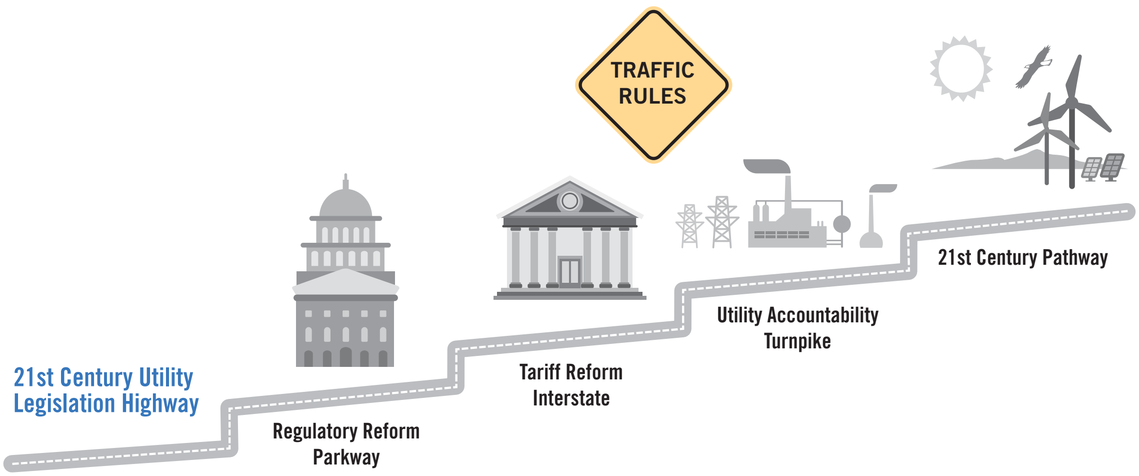
- Enhanced reliability and resilience of the electric grid while retaining affordability;
- An increase in cleaner energy to protect our environment and global strategic interests;
- Optimized system energy loads and electric-system efficiency to enhance cost efficiency and sustainability; and
- A focus on customer value, including service choices and ease of adoption.

Foundational Principles:

- Financially viable utilities essential to fund and support an enhanced electric grid;
- Policymakers must promote clear policy goals as part of a comprehensive, integrated 21st Century Utility Model;
- Commitment to engaging and empowering customers to make intelligent energy choices; and
- Equitable tariff structures that promote fairness and economic and environmental policy goals.

Pathway:

- State policymakers pursue legislation to outline the model for a 21st Century Utility;
- Regulatory reform to support efficient resource deployment and accountability;
- Tariff structures refined to support price signals and financial viability requirements;
- Utilities empowered and accountable for managing the Transition.



To make progress, it is important to begin this transition soon and oversee its continual evolution. The process to accomplish this transition is not regimented, but should include the following steps:

- define the objectives, vision and foundational principles for a 21st century electricity market;
- identify the transitional constraints and roadblocks to navigate to the end-state market;
- consider the roles and interactions of key market participants, including utilities and competitive service providers;
- define utility tariff structure objectives and approaches to realizing objectives;
- identify alternative incentives and hold utilities accountable for accelerating and integrating system optimization;
- define a timeline for commencing the study process and transition to the end state;
- identify a process to revise the utility model through the transition, as appropriate; and
- define the impact of the new model on the regulatory oversight process.

The policies set forth for a 21st Century Utility model and the pathway for achieving results will create a significant opportunity for economic growth and regional competitiveness.

No two states will apply the same approach, but the goal is to develop several robust models that can be tested and compared against each other to refine into best-in-class models over time. The policies set forth for a 21st Century Utility model and the pathway for achieving results will create a significant opportunity for economic growth and regional competitiveness. Over the long term, these proactive solutions will create shared benefits for customers, utility investors and society as a whole.

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Caught in a Fix

The Problem with Fixed Charges for Electricity

Prepared for Consumers Union

February 9, 2016

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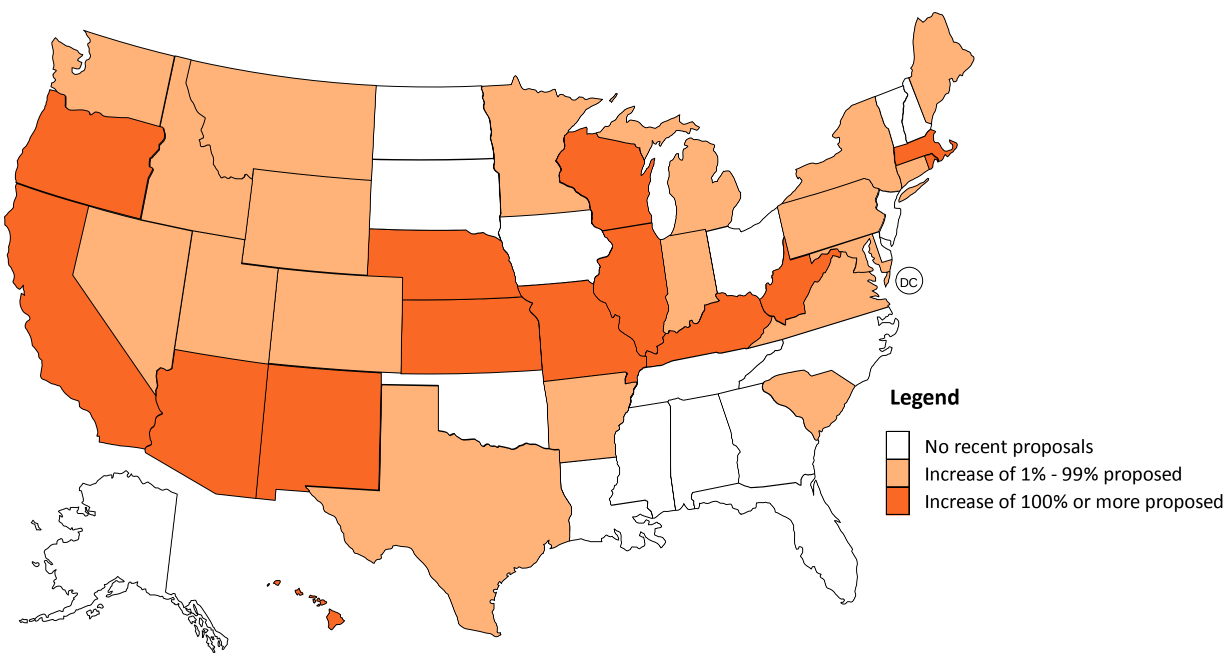
CONTENTS

EXECUTIVE SUMMARY

Recently, there has been a sharp increase in the number of utilities proposing to recover more of their costs through mandatory monthly fixed charges rather than through rates based on usage. Utilities prefer to collect revenue through fixed charges because the fixed charge reduces the utility's risk that lower sales (from energy efficiency, distributed generation, weather, or economic downturns) will reduce its revenues.

However, higher fixed charges are an inequitable and inefficient means to address utility revenue concerns. This report provides an overview of (a) how increased fixed charges can harm customers, (b) the common arguments that are used to support increased fixed charges, (c) recent commission decisions on fixed charges, and (d) alternative approaches, including maintaining the status quo when there is no serious threat to utility revenues.

Figure ES 1. Recent proposals and decisions regarding fixed charges



Source: See Appendix B

Fixed Charges Harm Customers

Reduced Customer Control. Since customers must pay the fixed charge regardless of how much electricity they consume or generate, the fixed charges reduce the ability of customers to lower their bills by consuming less energy.

Low-Usage Customers Hit Hardest. Customers who use less energy than average will experience the greatest percentage jump in their electric bills when the fixed charge is raised. There are many reasons a customer might have low energy usage: they may be very conscientious to avoid wasting energy; they may simply be located in apartments or dense housing units that require less energy; they may have small families or live alone; or they may have energy-efficient appliances or solar panels.

Disproportionate Impacts on Low-Income Customers. Data from the Energy Information Administration show that in nearly every state, low-income customers consume less electricity than other residential customers, on average. Because fixed charges tend to increase bills for low-usage customers while decreasing them for high-use customers, fixed charges raise bills most for those who can least afford the increase.

Reduced Incentives for Energy Efficiency and Distributed Generation. By reducing the value of a kilowatt-hour saved or self-generated, a higher fixed charge directly reduces the incentive that customers have to invest in energy efficiency or distributed generation. Customers who have already invested in energy efficiency or distributed generation will be harmed by the reduced value of their investments.

Increased Electricity System Costs. Holding all else equal, if the fixed charge is increased, the energy charge (cents per kilowatt-hour) will be reduced, thereby lowering the value of a kilowatt-hour conserved or generated by a customer. With little incentive to save, customers may actually increase their energy consumption and states will have to spend more to achieve the same levels of energy efficiency savings and distributed generation. Where electricity demand rises, utilities will need to invest in new power plants, power lines, and substations, thereby raising electricity costs for all customers.

Common Myths Supporting Fixed Charges

"Most utility costs are fixed." In accounting, fixed costs are those expenses that remain the same for a utility over the short and medium term regardless of the amount of energy its customers consume. Economics generally takes a longer-term perspective, in which very few costs are fixed. This perspective focuses on efficient investment decisions over the long-term planning horizon. Over this timeframe, most costs are variable, and customer decisions regarding their electricity consumption can influence the need to invest in power plants, transmission lines, and other utility infrastructure. This longer-term perspective is what is relevant for economically efficient price signals, and should be used to inform rate setting.

"Fixed costs are unavoidable." Rates are designed so that the utility can recover past expenditures (sunk costs) in the future. Utilities correctly argue that these sunk costs have already been made and are unavoidable. However, utilities should not, and generally do not, make decisions based on sunk costs; rather, they make investment decisions on a forward-looking basis. Similarly, rate structures should be based on forward-going costs to ensure that customers are being sent the right price signals, as customer consumption will drive future utility investments.

"The fixed charge should recover distribution costs." Much of the distribution system is sized to meet customer maximum demand – the maximum power consumed at any one time. For customer classes without a demand charge (such as residential customers),[1] utilities have argued that these distribution costs should be recovered through the fixed charge. This would allocate the costs of the distribution system equally among residential customers, instead of according to how much energy a customer uses. However, customers do not place equal demands on the system – customers who use more energy also tend to have higher demands. While energy usage (kWh) is not a perfect proxy for demand (kW), collecting demand-related costs through the energy charge is far superior to collecting demand-related costs through the fixed charge.

"Cost-of-service studies should dictate rate design." Cost-of-service studies are used to allocate a utility's costs among the various customer classes. These studies can serve as useful guideposts or benchmarks when setting rates, but the results of these studies should not be directly translated into rates. Embedded cost-of-service studies allocate *historical* costs to different classes of customers. However, to provide efficient price signals, prices should be designed to reflect *future* marginal costs. Rate designs other than fixed charges may yield the same revenue for the utility while also accomplishing other policy objectives, such as sending efficient price signals.

"Low-usage customers are not paying their fair share." This argument is usually untrue. As noted above, distribution costs are largely driven by peak demands, which are highly correlated with energy usage. Further, many low-usage customers live in multi-family housing or in dense neighborhoods, and therefore impose lower distribution costs on the utility system than high-usage customers.

"Fixed charges are necessary to mitigate cost-shifting caused by distributed generation." Concerns about potential cost-shifting from distributed generation resources, such as rooftop solar, are often dramatically overstated. While it is true that a host distributed generation customer provides less revenue to the utility than it did prior to installing the distributed generation, it is also true that the host customer provides the utility with a source of very low-cost power. This power is often provided to the system during periods when demand is highest and energy is most valuable, such as hot summer afternoons when the sun is out in full force. The energy from the distributed generation resource allows the utility to avoid the costs of generating, transmitting, and distributing electricity from its power plants. These avoided costs will put downward pressure on electricity rates, which will significantly reduce or completely offset the upward pressure on rates created by the reduced revenues from the host customer.

Recent Commission Decisions on Fixed Charges

Commissions in many states have recently rejected utility proposals to increase mandatory fixed charges. These proposals have been rejected on several grounds, including that increased fixed charges

[1] There are several reasons that demand charges are rarely assessed for residential customers. These reasons include the fact that demand charges introduce complexity into rates that may be inappropriate for residential customers; residential customers often lack the ability to monitor and respond to demand charges; and that residential customers often do not have more expensive meters capable of measuring customer demand.

will reduce customer control, send inefficient prices signals, reduce customer incentives to invest in energy efficiency, and have inequitable impacts on low-usage and low-income customers.

Several states have allowed utilities to increase fixed charges, but typically to a much smaller degree than has been requested by utilities. In addition, there have been many recent rate case settlements in which the utility proposal to increase fixed charges has been rejected by the settling parties. Nevertheless, utilities continue to propose higher fixed charges, as any increase in the fixed charge helps to protect the utility from lower revenues associated with reduced sales, whether due to energy efficiency, distributed generation, or any other reason.

Alternatives to Fixed Charges

For most utilities, there is no need for increased fixed charges. Regulators who decide there is a need to address utility revenue sufficiency and volatility concerns should consider alternatives to increased fixed charges, such as minimum bills and time-of-use rates.

1. INTRODUCTION

In 2014, Connecticut Light & Power filed a proposal to increase residential electricity customers' fixed monthly charge by 59 percent — from $16.00 to $25.50 per month — leaving customers angry and shocked. The fixed charge is a mandatory fee that customers must pay each month, regardless of how much electricity they use.

The utility's fixed charge proposal met with stiff opposition, particularly from seniors and customers on limited incomes who were trying hard to save money by reducing their electricity usage. Since the fixed charge is unavoidable, raising it would reduce the ability of customers to manage their bills and would result in low-usage customers experiencing the greatest percentage increase in their bills. In a letter imploring the state commission to reject the proposal, a retired couple wrote: "We have done everything we can to lower our usage… We can do no more. My wife and I resorted to sleeping in the living room during the month of January to save on electricity."[2]

Customers were particularly opposed to the loss of control that would accompany such an increase in the mandatory fixed charge, writing: "If there has to be an increase, at least leave the control in the consumers' hands. Charge based on the usage. At least you are not penalizing people who have sacrificed to conserve energy or cut their expenses."[3]

Unfortunately, customers in Connecticut are not alone. Recently, there has been a sharp uptick in the number of utilities that are proposing to recover more of their costs through monthly fixed charges rather than through variable rates (which are based on usage). Some of these proposals represent a slow, gradual move toward higher fixed charges, while other proposals (such as Madison Gas & Electric's) would quickly lead to a dramatic increase in fixed charges of nearly $70 per month.[4]

"If there has to be an increase, at least leave the control in the consumers' hands. Charge based on the usage. At least you are not penalizing people who have sacrificed to conserve energy or cut their expenses."

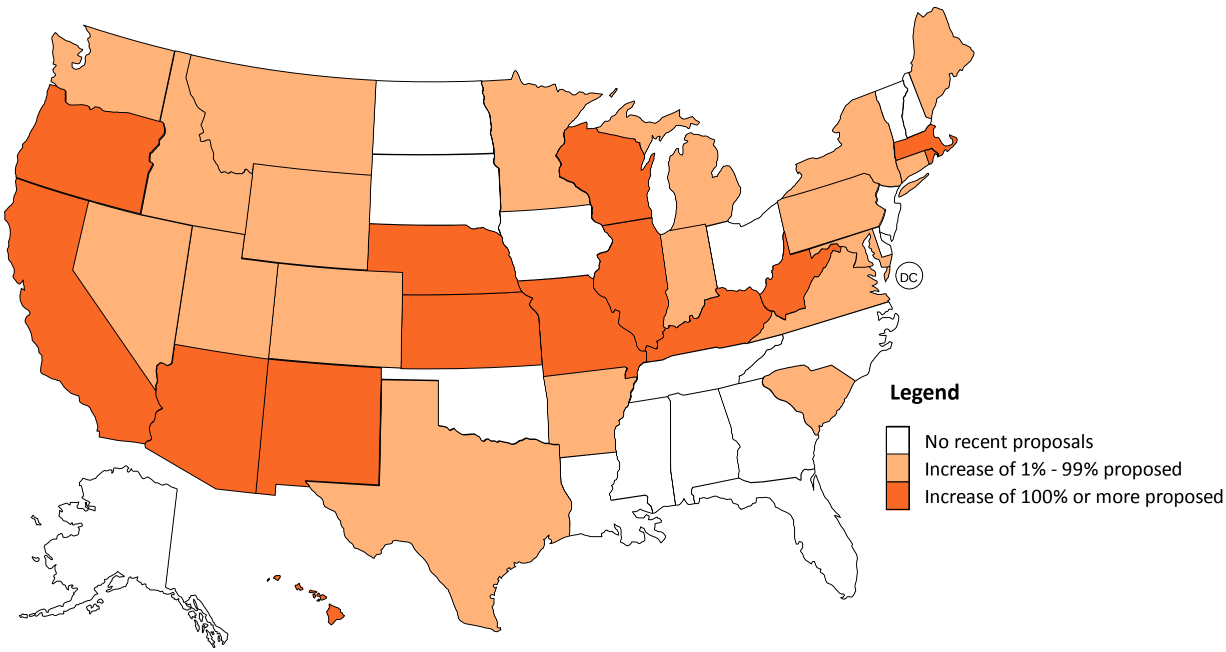
The map below shows the prevalence of recent utility proposals to increase the fixed charge, as well as the relative magnitude of these proposals. Proposals to increase the fixed charge were put forth or decided in 32 states in 2014 and 2015. In 14 of these states, the utility's proposal would increase the fixed charge by more than 100 percent.

[2] Written comment of John Dupell, Docket 14-05-06, filed May 30, 2014

[3] Written comment of Deborah Pocsay, Docket 14-05-06, July 30, 2014.

[4] Madison Gas & Electric's proposal for 2015/2016 offered a preview of its 2017 proposal, which featured a fixed charge of $68.37. Data from Ex.-MGE-James-1 in Docket No. 3270-UR-120.

Figure 1. Recent proposals and decisions regarding fixed charges



Source: See Appendix B

Although a fixed charge may be accompanied by a commensurate reduction in the energy charge, higher fixed charges have a detrimental impact on efficiency and equity. Utilities prefer to collect revenue through fixed charges because the fixed charge reduces the utility's risk that lower sales resulting from energy efficiency, distributed generation, weather, or economic downturns will reduce its revenues. However, higher fixed charges are not an equitable solution to this problem. Fixed charges reduce customers' control over their bills, disproportionately impact low-usage and low-income customers, dilute incentives for energy efficiency and distributed generation, and distort efficient price signals.

As the frequency of proposals to increase fixed charges rises, so too does awareness of their detrimental impacts. Fortunately, customers in Connecticut may soon obtain some relief: On June 30, 2015, the governor signed into law a bill that directs the utility commission to adjust utilities' residential fixed charges to only recover the costs "directly related to metering, billing, service connections and the

Fixed charges reduce customers' control over their bills, disproportionately impact low-usage and low-income customers, dilute incentives for energy efficiency and distributed generation, and distort efficient price signals.

provision of customer service."[5] However, not all policymakers are yet aware of the impacts of fixed charges or what alternatives might exist. The purpose of this report is to shed light on these issues.

Chapter 2 of this report examines the trends and drivers behind fixed charges, while Chapter 3 provides an assessment of how fixed charges impact customers. In Chapter 4, we explore many of the common technical arguments used to support these charges, and explain the flaws in these approaches. Finally, in Chapter 5, we provide an overview of some of the alternatives to fixed charges and the advantages and disadvantages of these alternatives.

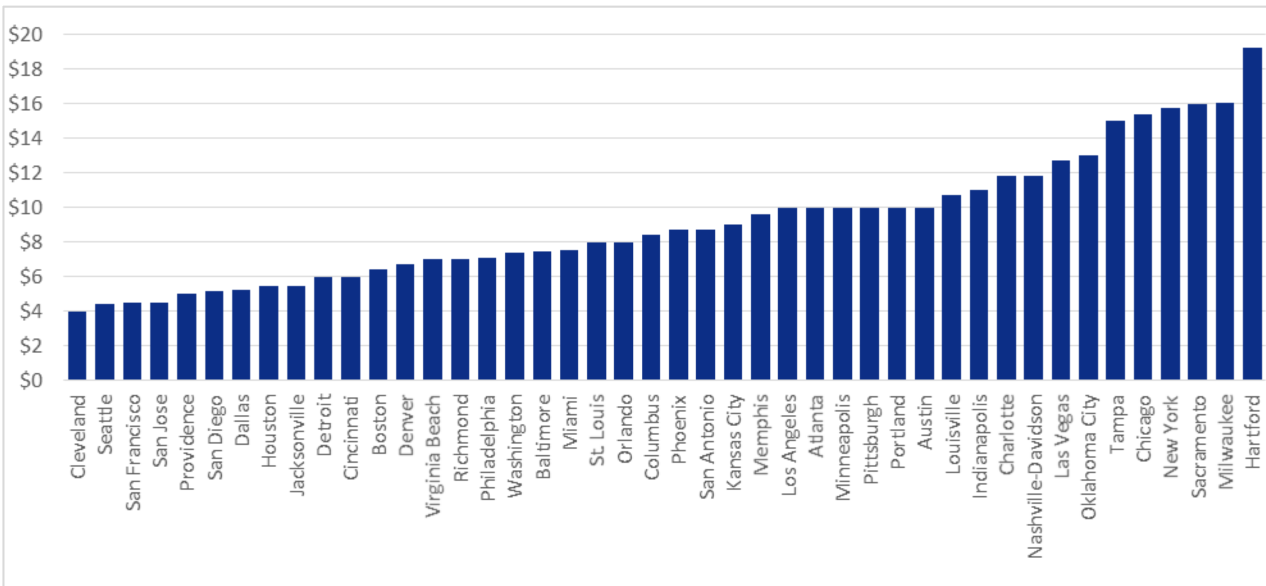
[5] Senate Bill No. 1502, June Special Session, Public Act No. 15-5, "An Act Implementing Provisions of the State Budget for The Biennium Ending June 30, 2017, Concerning General Government, Education, Health and Human Services and Bonds of the State."

2. TROUBLING TRENDS TOWARD HIGHER FIXED CHARGES

What's Happening to Electric Rates?

Sometimes referred to as a "customer charge" or "service charge," the fixed charge is a flat fee on a customer's monthly bill that is typically designed to recover the portion of costs that do not vary with usage. These costs may include, for examples, costs of meters, service lines, meter reading, and customer billing.[6] In most major U.S. cities, the fixed charge ranges from $5 per month to $10 per month, as shown in the chart below.[7]

Figure 2. Fixed charges in major U.S. cities



Source: Utility tariff sheets for residential service as of August 19, 2015.

Although fixed charges have historically been a small part of customers' bills, more and more utilities across the country—from Hawaii to Maine—are seeking to increase the portion of the bill that is paid through a flat, monthly fixed charge, while decreasing the portion that varies according to usage.

[6] Frederick Weston, "Charging for Distribution Utility Services: Issues in Rate Design," Prepared for the National Association of Regulatory Utility Commissioners (Montpelier, VT: Regulatory Assistance Project, December 2000).

[7] Based on utility tariff sheets for residential service as of August 2015.

Connecticut Light & Power's proposed increase in the fixed charge to $25.50 per month was significantly higher than average,[8] but hardly unique.

Other recent examples include:

- The Hawaiian Electric Companies' proposal to increase the customer charge from $9.00 to $55.00 per month (an increase of $552 per year) for full-service residential customers, and $71.00 per month for new distributed generation customers (an increase of $744 per year);[9]
- Kansas City Power and Light's proposal to increase residential customer charges 178 percent in Missouri, from $9.00 to $25.00 per month (an increase of $192 per year);[10] and
- Pennsylvania Power and Light's March 2015 proposal to increase the residential customer charge from approximately $14.00 to approximately $20.00 per month (an increase of more than $70 per year).[11]

Figure 3 below displays those fixed charge proposals that are currently pending, while Figure 4 displays the proposals that have been ruled upon in 2014-2015.

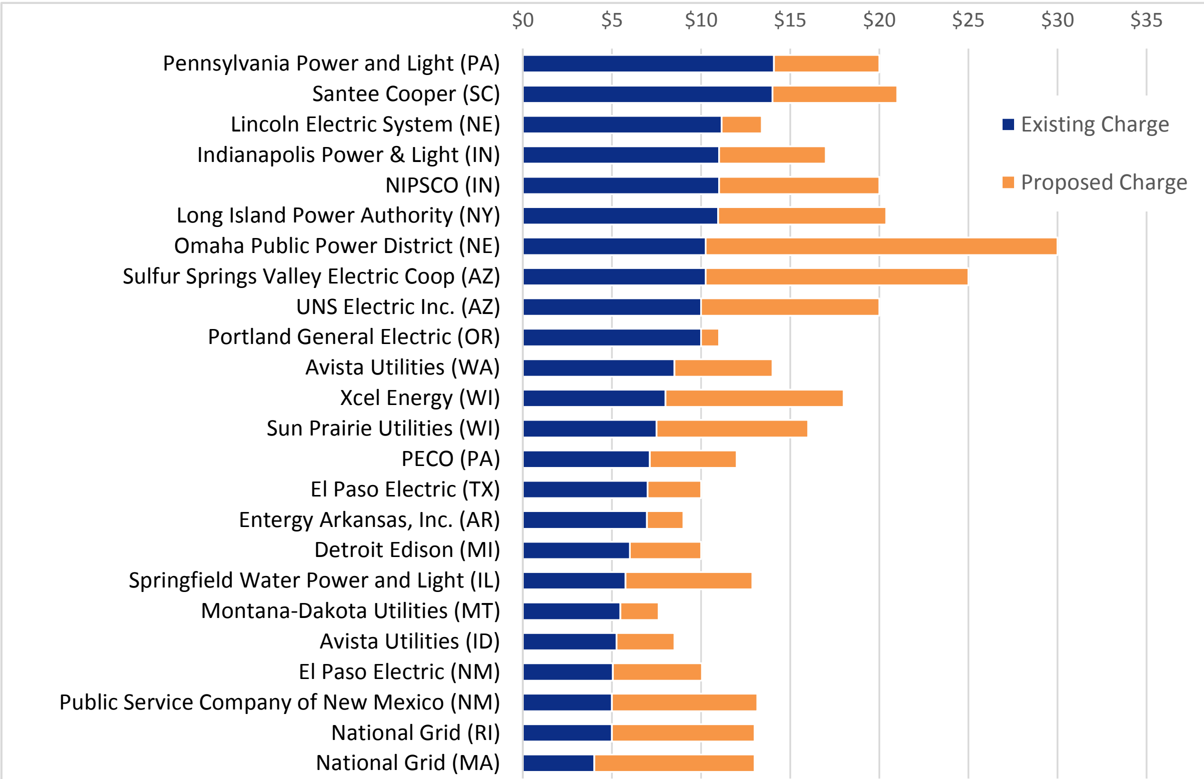
[8] Ultimately the commission approved a fixed charge of $19.25, below the utility's request, but among the highest in the country.

[9] Hawaiian Electric Companies' Distributed Generation Interconnection Plan, Docket 2011-0206, submitted August 26, 2014, at http://files.hawaii.gov/puc/3_Dkt 2011-0206 2014-08-26 HECO PSIP Report.pdf.

[10] Kansas City Power and Light, Case No.: ER-2014-0370.

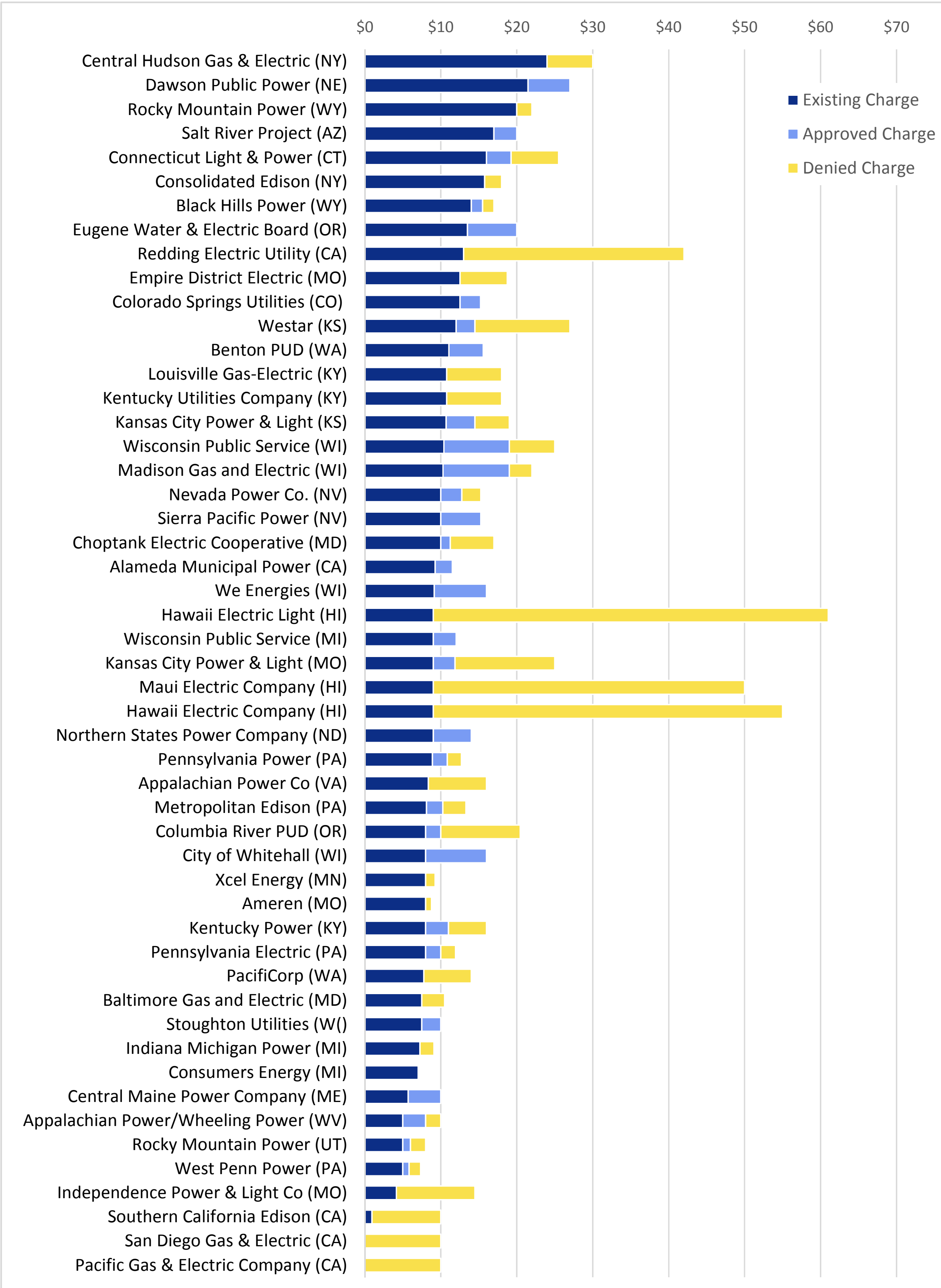
[11] PPL Witness Scott R. Koch, Exhibit SRK 1, Supplement No. 179 to Tariff – Electric Pa. P.U.C. No. 201, Docket No. R-2015-2469275, March 31, 2015, at http://www.puc.state.pa.us/pcdocs/1350814.pdf.

Figure 3. Pending proposals for fixed charge increases



Source: See Appendix B

Figure 4. Recent decisions regarding fixed charge proposals



Notes: "Denied" includes settlements that did not increase the fixed charge. Source: See Appendix B

What is Behind the Trend Toward Higher Fixed Charges?

It is important to note that the question of whether to increase the fixed charge is a rate design decision. Rate design is not about how *much* total revenue a utility can collect; rather, rate design decisions determine *how* the utility can collect a set amount of revenue from customers. That is, once the amount of revenues that a utility can collect is determined by a commission, rate design determines the method for collecting that amount. However, if electricity sales deviate from the predicted level, a utility may actually collect more or less revenue than was intended.

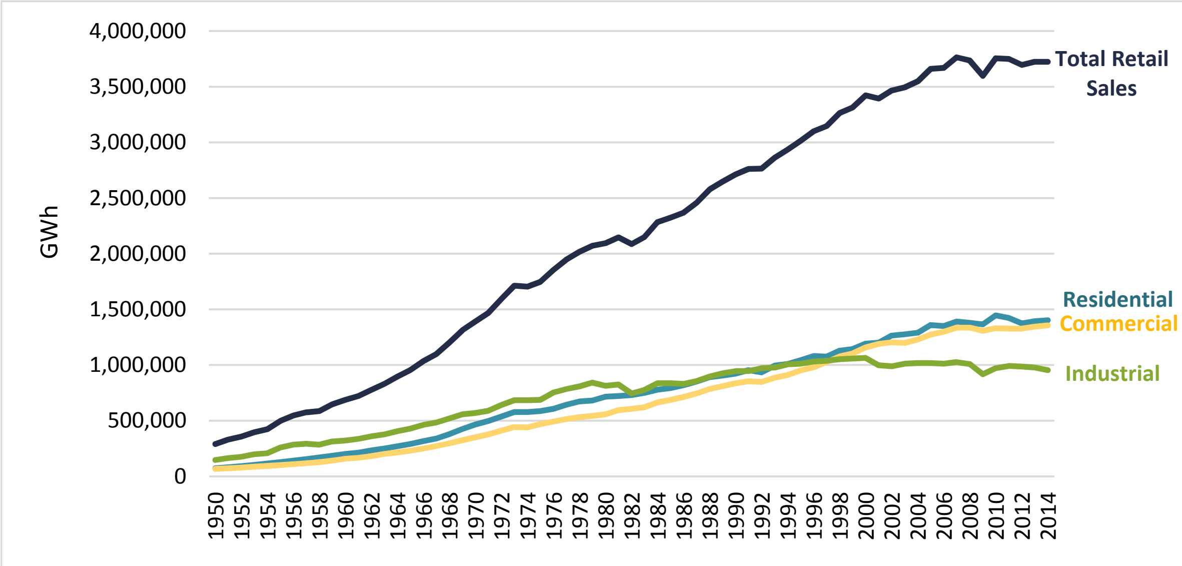
Rates are typically composed of some combination of the following three types of charges:

- Fixed charge: dollars per customer
- Energy charge: cents per kilowatt-hour (kWh) used
- Demand charge: dollars per kilowatt (kW) of maximum power used[12]

Utilities have a clear motivation for proposing higher fixed charges, as the more revenue that a utility can collect through a fixed monthly charge, the lower the risk of revenue under-recovery. Revenue certainty is an increasing concern for utilities across the country as sales stagnate or decline. According to the U.S. Energy Information Administration, electricity sales have essentially remained flat since 2005, as shown in Figure 5 below. This trend is the result of many factors, including greater numbers of customers adopting energy efficiency and distributed generation—such as rooftop solar—as well as larger economic trends. This trend toward flat sales is in striking contrast to the growth in sales that utilities have experienced since 1950, and has significant implications for utility cost recovery and ratemaking.

[12] Demand charges are typically applied only to medium to large commercial and industrial customers. However, some utilities are seeking to start applying demand charges to residential customers who install distributed generation.

Figure 5. Retail electricity sales by sector



Source: U.S. Energy Information Administration, September 2015 Monthly Energy Review, Table 7.6 Electricity End Use.

Reduced electricity consumption—whether due to customer conservation efforts, rooftop solar, or other factors—strikes at the very heart of the traditional utility business model, since much of a utility's revenue is tied directly to sales. As Kansas City Power and Light recently testified:

> From the Company perspective, reductions in usage, driven by reduced customer growth, energy efficiency, or even customer self-generation, result in under recovery of revenues. Growth would have compensated or completely covered this shortfall in the past. With the accelerating deployment of initiatives that directly impact customer growth, it is becoming increasingly difficult for the Company to accept this risk of immediate under recovery.[13]

At the same time that sales, and thus revenue growth, have slowed, utility costs have increased, as much utility infrastructure nears retirement age and needs replacement. The American Society of Civil Engineers estimates that $57 billion must be invested in electric distribution systems by 2020, and another $37 billion in transmission infrastructure.[14]

[13] Direct Testimony of Tim Rush, Kansas City Power & Light, Docket ER-2014-0370, October 2014, page 63.

[14] American Society of Civil Engineers, "2013 Report Card for America's Infrastructure: Energy," 2013, http://www.infrastructurereportcard.org.

3. How Fixed Charges Harm Customers

Reduced Customer Control

As technology advances, so too have the opportunities for customers to monitor and manage their electricity consumption. Many utilities are investing in smart meters, online information portals, and other programs and technologies in the name of customer empowerment. "We think customer empowerment and engagement are critical to the future of energy at Connecticut Light & Power and across the nation," noted the utility's director of customer relations and strategy.[15]

The fixed charge reduces customer control, as the only way to avoid the charge is to stop being a utility customer.

Despite these proclamations of support for customer empowerment and ratepayer-funded investments in demand-management tools, utilities' proposals for raising the fixed charge actually serve to disempower customers. Since customers must pay the fixed charge regardless of how much electricity they consume or generate, the fixed charge reduces the ability of customers to lower their bills by consuming less energy. Overall, the fixed charge reduces customer control, as the only way to avoid the fixed charge is to stop being a utility customer, an impossibility for most customers

Low-Usage Customers Hit Hardest

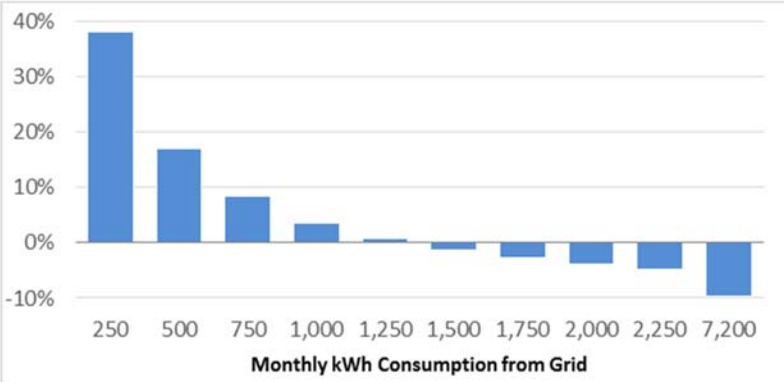
Customers who use less energy than average will experience the greatest percentage jump in their electric bills when the fixed charge is raised, since bills will then be based less on usage and more on a flat-fee structure. There are many reasons why a customer might have low energy usage. Low-usage customers may have invested in energy-efficient appliances or installed solar panels, or they may have lower incomes and live in dense housing.

Figure 6 illustrates the impact of increasing the fixed charge for residential customers from $9.00 per month to $25.00 per month, with a corresponding decrease in the per-kilowatt-hour charge. Customers who consume 1,250 kilowatt-hours per month would see virtually no change in their monthly bill, while low-usage customers who consume only 250 kilowatt-hours per month would see their bill rise by nearly 40 percent. High usage customers (who tend to have higher incomes) would see a bill decrease. The data presented in the figure approximates the impact of Kansas City Power & Light's recently proposed rate design.[16]

[15] Phil Carson, "Connecticut Light & Power Engages Customers," *Intelligent Utility*, July 1, 2011, http://www.intelligentutility.net/article/11/06/connecticut-light-power-engages-customers?quicktabs_4=2&quicktabs_11=1&quicktabs_6=1.

[16] Missouri Public Service Commission Docket ER-2014-0370.

Figure 6. Increase in average monthly bill

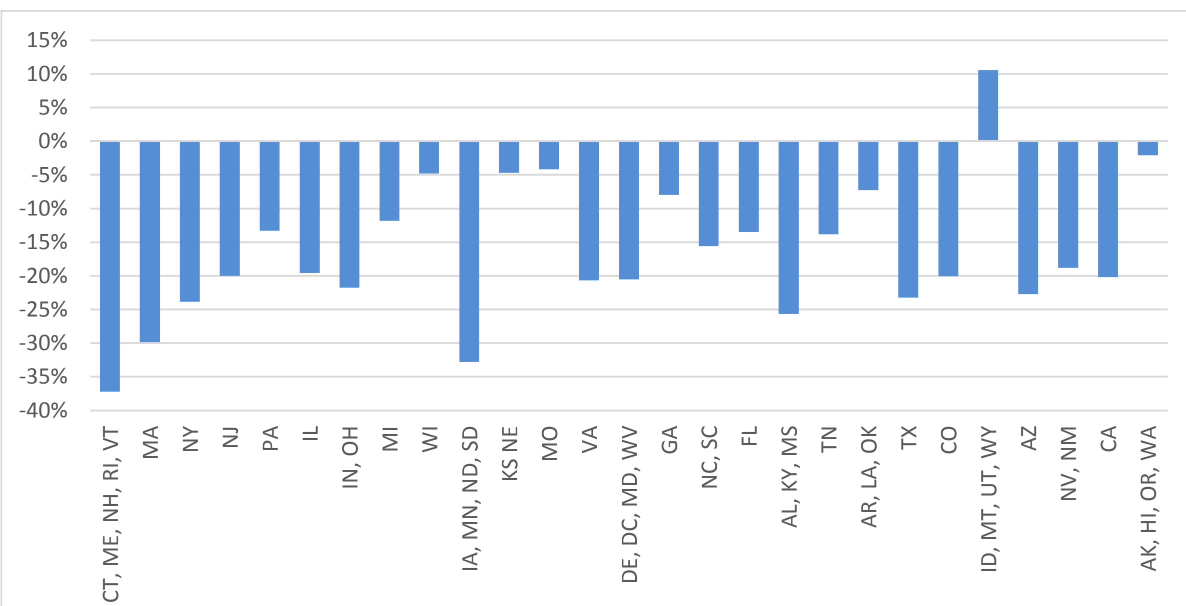


Analysis based on increasing the fixed charge from $9/month to $25/month, with a corresponding decrease in the $/kWh charge.

Disproportionate Impacts on Low-Income Customers

Low-income customers are disproportionately affected by increased fixed charges, as they tend to be low-usage customers. Figure 7 compares median electricity consumption for customers at or below 150 percent of the federal poverty line to electricity consumption for customers above that income level, based on geographic region. Using the median value provides an indication of the number of customers above or below each usage threshold—by definition, 50 percent of customers will have usage below the median value. As the graph shows, in nearly every region, most low-income customers consume less energy than the typical residential customer.

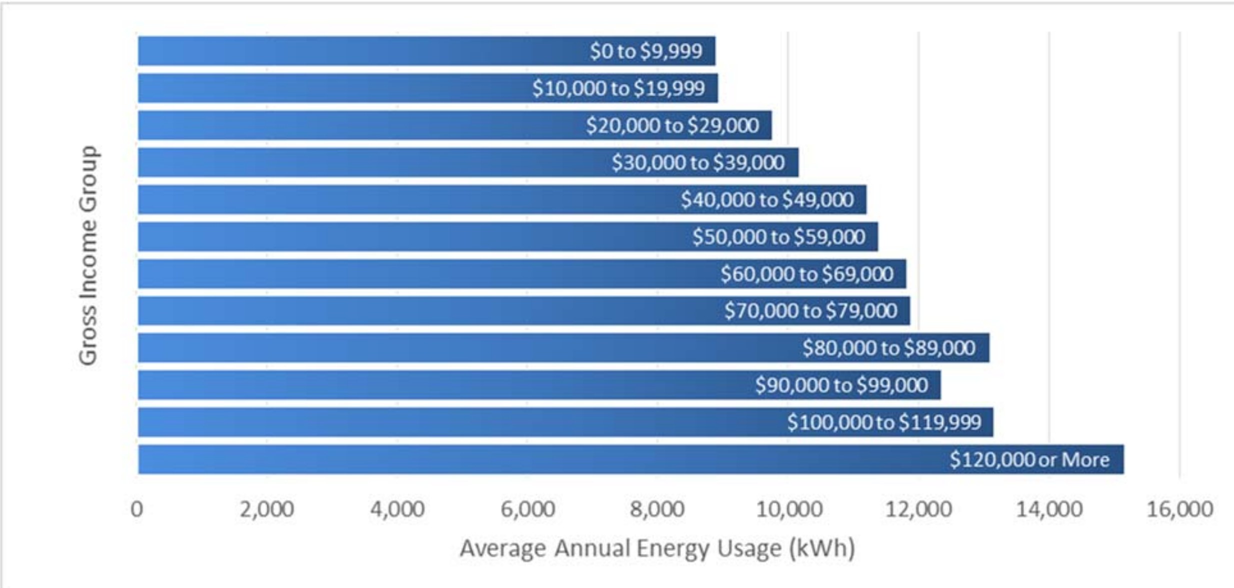
Figure 7. Difference between low-income median residential electricity usage and non-low-income usage



Source: Energy Information Administration Residential Energy Consumption Survey, 2009. http://www.eia.gov/consumption/residential/data/2009. Developed with assistance from John Howat, Senior Policy Analyst, NCLC.

The same relationship generally holds true for average usage. Nationwide, as gross income rises, so does average electricity consumption, generally speaking.

Figure 8. Nationwide average annual energy usage by income group



Source: Energy Information Administration Residential Energy Consumption Survey, 2009
http://www.eia.gov/consumption/residential/data/2009.

Because fixed charges tend to increase bills for low-usage customers while decreasing them for high-use customers, higher fixed charges tend to raise bills most for those who can least afford the increase. This shows that rate design has important equity implications, and must be considered carefully to avoid regressive impacts.

Reduced Incentives for Energy Efficiency and Distributed Generation

Energy efficiency and clean distributed generation are widely viewed as important tools for helping reduce energy costs, decrease greenhouse gas emissions, create jobs, and improve economic competitiveness. Currently, ratepayer-funded energy efficiency programs are operating in all 50 states and the District of Columbia.[17] These efficiency programs exist alongside numerous other government policies, including building codes and appliance standards, federal weatherization assistance, and tax incentives. Distributed generation (such as rooftop solar) is commonly supported through tax incentives and net energy metering programs that compensate customers who generate a portion of their own electricity.

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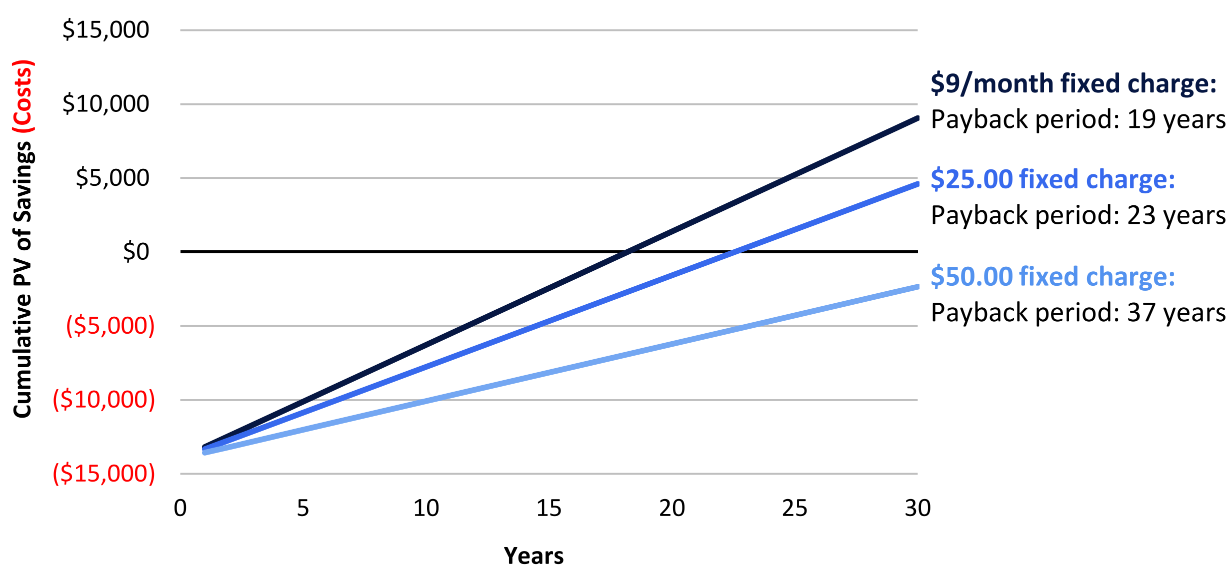
[17] Annie Gilleo et al., "The 2014 State Energy Efficiency Scorecard" (American Council for an Energy Efficient Economy, October 2014).

Increasing fixed charges can significantly reduce incentives for customers to reduce consumption through energy efficiency, distributed generation, or other means. By reducing the value of a kilowatt-hour saved or self-generated, a higher fixed charge directly reduces the incentive that customers have to lower their bills by reducing consumption. Customers who are considering making investments in energy efficiency measures or distributed generation will have longer payback periods over which to recoup their initial investment. In some cases, a customer might never break even financially when the fixed charge is increased. Increasing the fixed charge also penalizes customers who have already taken steps to reduce their energy consumption by implementing energy efficiency measures or installing distributed generation.

"When has it ever been the right of a company under any ethical business practices to penalize their customers for being efficient, conservative and environmentally responsible?"

Figure 9 illustrates how the payback period for rooftop solar can change under a net metering mechanism with different fixed charges. Under net metering arrangements, a customer can offset his or her monthly electricity usage by generating solar electricity—essentially being compensated for each kilowatt-hour produced. However, solar customers typically cannot avoid the fixed charge. For a fairly typical residential customer, raising the fixed charge from $9.00 per month to $25.00 per month could change the payback period for a 5 kW rooftop solar system from 19 years to 23 years – longer than the expected lifetime of the equipment. Increasing the fixed charge to $50.00 per month further exacerbates the situation, causing the project to not break even until 37 years in the future, and virtually guaranteeing that customers with distributed generation will face a significant financial loss.

Figure 9. Rooftop solar payback period under various customer charges



All three scenarios assume monthly consumption of 850 kWh. The $9.00 per month fixed charge assumes a corresponding energy charge of 10.36 cents per kWh, while the $25 fixed charge assumes an energy charge of 8.48 cents per kWh, and the $50 fixed charge assumes an energy charge of 5.54 cents per kWh.

In Connecticut, customers decried the proposed fixed charge as profoundly unfair: "When has it ever been the right of a company under any ethical business practices to penalize their customers for being efficient, conservative and environmentally responsible?" noted one frustrated customer. "Where is the incentive to spend hard-earned money to improve your appliances, or better insulate your home or more efficiently set your thermostats or air conditioning not to be wasteful, trying to conserve energy for the next generation - when you will allow the utility company to just turn around and now charge an additional fee to offset your savings?"[18]

Increased Electricity System Costs

High fixed charges may actually encourage customers to leave the system, leaving fewer and fewer customers to shoulder the costs of the electric system.

Because higher fixed charges reduce customer incentives to reduce consumption, they will undermine regulatory policies and programs that promote energy efficiency and clean distributed generation, leading to higher program costs, diminished results, or both. Rate design influences the effectiveness of these regulatory policies by changing the price signals that customers see. Holding all else equal, if the fixed charge is increased, the energy charge (cents per kilowatt-hour) will be reduced, thereby lowering the value of a kilowatt-hour conserved or generated by a customer.

The flip side of this is that customers may actually increase their energy consumption since they perceive the electricity to be cheaper. Under such a scenario, states will have to spend more funds on incentives to achieve the same level of energy efficiency savings and to encourage the same amount of distributed generation as achieved previously at a lower cost. Where electricity demand is not effectively reduced, utilities will eventually need to invest in new power plants, power lines, and substations, thereby raising electricity costs for all customers.

In extreme cases, high fixed charges may actually encourage customers to leave the system. As rooftop solar and storage costs continue to fall, some customers may find it less expensive to generate all of their own electricity without relying on the utility at all. Once a customer departs the system, the total system costs must be redistributed among the remaining customers, raising electricity rates. These higher rates may then lead to more customers defecting, leaving fewer and fewer customers to shoulder the costs.

Where electricity demand is not effectively reduced, utilities will eventually need to invest in new power plants, power lines, and substations, thereby raising electricity costs for all customers.

The end result of having rate design compete with public policy incentives is that customers will pay more—either due to higher energy efficiency and distributed generation program costs, or through more investments needed to meet higher electricity demand. Meanwhile, customers who have already invested in energy efficiency or distributed generation will get burned by the reduced value of their investments and may choose to

[18] Written comment of Deborah Pocsay, Docket 14-05-06, July 30, 2014.

leave the grid, while low-income customers will experience higher bills, and all customers will have fewer options for reducing their electricity bills.

4. Rate Design Fundamentals

To understand utilities' desire to increase the fixed charge—and some of the arguments used to support or oppose these proposals—it is first necessary to review how rates are set.

Guiding Principles

Rates are designed to satisfy numerous objectives, some of which may be in competition with others. In his seminal work, *Principles of Public Utility Rates,* Professor James Bonbright enumerated ten guiding principles for rate design. These principles are reproduced in the appendix, and can be summarized as follows:

1. Sufficiency: Rates should be designed to yield revenues sufficient to recover utility costs.
2. Fairness: Rates should be designed so that costs are fairly apportioned among different customers, and "undue discrimination" in rate relationships is avoided.
3. Efficiency: Rates should provide efficient price signals and discourage wasteful usage.
4. Customer acceptability: Rates should be relatively stable, predictable, simple, and easily understandable.

Different parts of the rate design process address different principles. First, to determine sufficient revenues, the utility's revenue requirement is determined based on a test year (either future or historical). Second, a cost-of-service study divides the revenue requirement among all of the utility's customers according to the relative cost of serving each class of customers based on key factors such as the number of customers, class peak demand, and annual energy consumption. Third, marginal costs may be used to inform efficient pricing levels. Finally, rates are designed to ensure that they send efficient price signals, and are relatively stable, understandable, and simple.

Cost-of-Service Studies

Cost-of-service study results are often used when designing rates to determine how the revenue requirement should be allocated among customer classes. An *embedded* cost-of-service study generally begins with the revenue requirement and allocates these costs among customers. An embedded cost-of-service study is performed in three steps:

- First, costs are functionalized, meaning that they are defined based upon their function (e.g., production, distribution, transmission).
- Second, costs are classified as energy-related (which vary by the amount of energy a customer consumes), demand-related (which vary according to customers' maximum energy demand), or customer-related (which vary by the number of customers).

- Finally, these costs are allocated to the appropriate customer classes. Costs are allocated on the principle of "cost causation," where customers that cause costs to be incurred should be responsible for paying them. Unit costs (dollars per kilowatt-hour, per kilowatt of demand, or per customer-month) from the cost-of-service study can be used as a point of reference for rate design.

A *marginal* cost study differs from an embedded cost study in that it is forward-looking and analyzes how the costs of the electric system would change if demand increased. A marginal cost study is particularly useful for informing rate design, since according to economic theory, prices should be set equal to marginal cost to provide efficient price signals.

One of the challenges of rate design comes from the need to reconcile the differences between embedded and marginal cost-of-service studies. Rates need to meet the two goals of allowing utilities to recover their historical costs (as indicated in embedded cost studies), and providing customers with efficient price signals (as indicated in marginal cost studies).

It is worth noting that there are numerous different approaches to conducting cost-of-service studies, and thus different analysts can reach different results.[19] Some jurisdictions consider the results of multiple methodologies when setting rates.

Rate Design Basics

Most electricity customers are charged for electricity using a two-part or three-part tariff, depending on the customer class. Residential customers typically pay a monthly fixed charge (e.g., $9 per month) plus an energy charge based on usage (e.g., $0.10 per kilowatt-hour).[20] The fixed charge (or "customer charge") is generally designed to recover the costs to serve a customer that are largely independent of usage, such as metering and billing costs, while the energy charge reflects the cost to generate and deliver energy.

Commercial and industrial customers frequently pay for electricity based on a three-part tariff consisting of a fixed charge, an energy charge, and a demand charge, because they are large users and have meters capable of measuring demand as well as energy use. The demand charge is designed to reflect the maximum amount of energy a customer withdraws at any one time, often measured as the maximum demand (in kilowatts) during the billing month. While the fixed charge is still designed to recover customer costs that are largely independent of usage, the cost to deliver energy through the transmission and distribution system is recovered largely through the demand charge, while the energy charge primarily reflects fuel costs for electricity generation.

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[19] Commonly used cost-of-service study methods are described in the *Electric Utility Cost Allocation Manual*, published by the National Association of Regulatory Utility Commissioners.

[20] There are many variations of energy charge; the charge may change as consumption increases ("inclining block rates"), or based on the time of day ("time-of-use rates").

5. Common Arguments Supporting Higher Fixed Charges

"Most Utility Costs Are Fixed"

Argument

Utilities commonly argue that most of their costs are fixed, and that that the fixed charge is appropriate for recovering such "fixed" costs. For example, in its 2015 rate case, National Grid stated, "as the nature of these costs is fixed, the proper price signal for the recovery of these costs should also be fixed to the extent possible."[21]

Response

This argument conflates the accounting definition with the economic definition of fixed and variable costs.

- In accounting, fixed costs are those expenses that remain the same for a utility over the short and medium term regardless of the amount of energy its customers consume. In this sense of the term, fixed costs can include poles, wires, and power plants.[22] This definition contrasts with variable costs, which are the costs that are directly related to the amount of energy the customer uses and that rise or fall as the customer uses more or less energy.
- Economics generally takes a longer-term perspective, in which very few costs are fixed. This perspective focuses on efficient investment decisions over the planning horizon—perhaps a term of 10 or more years for an electric utility. Over this timeframe, most costs are variable.

Because utilities must recover the costs of the investments they have already made in electric infrastructure, they frequently employ the accounting definition of fixed costs and seek to ensure that revenues match costs. This focus is understandable. However, this approach fails to provide efficient price signals to customers. As noted above, it is widely accepted in economics that resource allocation is most efficient when all goods and services are priced at marginal cost. For efficient electricity investments to be made, the marginal cost must be based on the appropriate timeframe. In *Principles of Public Utility Rates*, James Bonbright writes:

> I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant

[21] National Grid Pricing Panel testimony, Book 7 of 9, Docket No. D.P.U. 15-155, November 6, 2015, page 36.

[22] Many of these costs are also "sunk" in the sense that the utility cannot easily recover these investments once they have been made.

> marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or "capacity costs" as variable costs.[23]

A fixed charge that includes long-run marginal costs provides no price signal relevant to resource allocation, since customers cannot reduce their consumption enough to avoid the charge. In contrast, an energy charge that reflects long-run marginal costs will encourage customers to consume electricity efficiently, thereby avoiding inefficient future utility investments.

"Fixed Costs Are Unavoidable"

Argument

By classifying some utility costs as "fixed," utilities are implying that these costs remain constant over time, regardless of customer energy consumption.

Response

Past utility capital investments are depreciated over time, and revenues collected through rates must be sufficient to eventually pay off these past investments. While these past capital investments are fixed in the sense that they cannot be avoided (that is, they are "sunk costs"), some future capital investments can be avoided if customers reduce their energy consumption and peak demands. Inevitably, the utility will have to make new capital investments; load growth may require new generating equipment to be constructed or distribution lines to be upgraded. Rate design has a role to play in sending appropriate price signals to guide customers' energy consumption and ensure that efficient future investments are made.

In short, utilities should not, and generally do not, make decisions based on sunk costs; rather, they make investment decisions on a forward-looking basis. Similarly, rate structures should be analyzed to some degree on a forward-going basis to ensure that customers are being sent the right price signals, as customer consumption will drive future utility investments.

"The Fixed Charge Should Recover Distribution Costs"

Argument

The electric distribution system is sized to deliver enough energy to meet the maximum demand placed on the system. As such, the costs of the distribution system are largely based on customer peak demands, which are measured in kilowatts. For this reason, large customers typically face a demand charge that is based on the customer's peak demand. Residential customers, however, typically do not have the metering capabilities required for demand charges, nor do they generally have the means to

[23] James Bonbright, Principles of Public Utility Rates (New York: Columbia University Press, 1961). P. 336.

monitor and reduce their peak demands. Residential demand-related costs have thus historically been recovered through the energy charge.

Where demand charges are not used, utilities often argue that these demand-related costs are better recovered through the fixed charge, as opposed to the energy charge. Similar to the arguments above, utilities often claim that the costs of the distribution system—poles, wires, transformers, substations, etc.— are "fixed" costs.[24]

Response

While the energy charge does not perfectly reflect demand-related costs imposed on the system, it is far superior to allocating demand-related costs to all residential customers equally through the fixed charge. Recent research has demonstrated that there exists "a strong and significant correlation between monthly kWh consumption and monthly maximum kW demand," which suggests that "it is correct to collect most of the demand-related capacity costs through the kWh energy charge."[25]

Not all distribution system costs can be neatly classified as "demand-related" or "customer-related," and there is significant gray area when determining how these costs are classified. In general, however, the fixed charge is designed to recover customer-related costs, not any distribution-system cost that does not perfectly fall within the boundaries of "demand-related" costs. Bonbright himself warned against misuse of the fixed charge, stating that a cost analyst is sometimes "under compelling pressure to 'fudge' his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other categories."[26]

Where it is used at all, the customer (fixed) charge should be limited to only recovering costs that vary directly with the number of customers, such as the cost of the meter, service drop, and customer billing, as has traditionally been done.[27]

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[24] For example, in UE-140762, PacifiCorp witness Steward testifies that "Distribution costs (along with retail and miscellaneous) are fixed costs associated with the local facilities necessary to connect and serve individual customers. Accordingly, these costs should be recovered through the monthly basic charges and load size charges (which are based on demand measurements)." JRS-1T, p. 17. Another example is provided in National Grid's 2015 rate case application. The utility's testimony states: "the distribution system is sized and constructed to accommodate the maximum demand that occurs during periods of greatest demand, and, once constructed, distribution system costs are fixed in nature. In other words, reducing energy consumption does not result in a corresponding reduction in distribution costs. Therefore, as the nature of these costs is fixed, the proper price signal for the recovery of these costs should also be fixed to the extent possible." D.P.U. 15-155, Pricing Panel testimony, November 6, 2015, page 36.

[25] Larry Blank and Doug Gegax, "Residential Winners and Losers behind the Energy versus Customer Charge Debate," *Fortnightly* 27, no. 4 (May 2014).

[26] *Principles of Public Utility Rates*, Dr. James Bonbright, Columbia University Press, 1961, p. 349.

[27] Weston, 2000: "there is a broad agreement in the literature that distribution investment is causally related to peak demand" and not the number of customers; and "[t]raditionally, customer costs are those that are seen to vary with the number of customers on the system: service drops (the line from the distribution radial to the home or business), meters, and billing and collection." Pp. 28-29.

"Cost-of-Service Studies Should Dictate Rate Design"

Argument

Utilities sometimes argue that adherence to the principle of "cost-based rates" means that the unit costs identified in the cost-of-service study (i.e., dollars per kilowatt-hour, dollars per kilowatt, and dollars per customer) should be replicated in the rate design.

Response

The cost-of-service study can be used as a guide or benchmark when setting rates, but by itself it does not fully capture all of the considerations that should be taken into account when setting rates. This is particularly true if only an embedded cost-of-service study is conducted, rather than a marginal cost study. As noted above, embedded cost studies reflect only historical costs, rather than marginal costs. Under economic theory, prices should be set equal to marginal cost in order to provide an efficient price signal. Reliance on marginal cost studies does not fully resolve the issue, however, as marginal costs will seldom be sufficient to recover a utility's historical costs.

"I know of no ratemaking or economic principle that finds that cost structure must be replicated in rate design, especially when significant negative policy impacts are attendant to that approach."

Further, cost-of-service studies do not account for benefits that customers may be providing to the grid. In the past, customers primarily imposed costs on the grid by consuming energy. As distributed generation and storage become more common, however, customers are increasingly becoming "prosumers"—providing services to the grid as well as consuming energy. By focusing only on the cost side of the equation, cost-of-service studies generally fail to account for such services.

Cost-of-service study results are most useful when determining *how much* revenue to collect from different types of customers, rather than *how* to collect such revenue. Clearly, rates can be set to exactly mirror the unit costs revealed by the embedded cost-of-service study (dollars per customer, per kilowatt, or per kilowatt-hour), but other rate designs may yield approximately the same revenue while also accomplishing other policy objectives, particularly that of sending efficient price signals. Indeed, most products in the competitive marketplace—whether groceries, gasoline, or restaurant meals—are priced based solely on usage, rather than also charging a customer access fee and another fee based on maximum consumption.

This point was echoed recently by Karl Rabago, a former Texas utility commissioner: "I know of no ratemaking or economic principle that finds that cost structure must be replicated in rate design, especially when significant negative policy impacts are attendant to that approach."[28]

[28] Rabago direct testimony, NY Orange & Rockland Case 14-E-0493, p. 13.

As a final note, utility class cost of service studies are just that. They are performed by the utility and rely on numerous assumptions on how to allocate costs. Depending on the method and cost allocation chosen, results can vary dramatically, and represent one party's view of costs and allocation. Different studies can and do result in widely varying results. Policymakers should view with skepticism a utility claim that residential customers are not paying their fair share of costs based on such studies.

"Low-Usage Customers Are Not Paying Their Fair Share"

Argument

It is often claimed that a low fixed charge results in high-usage customers subsidizing low-usage customers.

Response

The reality is much more complicated. As noted above, distribution costs are largely driven by peak demands, which are highly correlated with energy usage. Thus, many low-usage customers impose lower demands on the system, and should therefore be responsible for a smaller portion of the distribution system costs. Furthermore, many low-usage customers live in multi-family housing or in dense neighborhoods, and therefore impose lower distribution costs on the utility system than high-usage customers.

"Fixed Charges Are Necessary to Mitigate Cost-Shifting Caused by Distributed Generation"

Argument

Several utilities have recently proposed that fixed customer charges should be increased to address the growth in distributed generation resources, particularly customer-sited photovoltaic (PV) resources. Utilities argue that customers who install distributed generation will not pay their "fair share" of costs, because they will provide much less revenue to the utility as a result of their decreased need to consume energy from the grid. This "lost revenue" must eventually be paid by other customers who do not install distributed generation, which will increase their electricity rates, causing costs to be shifted to them.

While it is true that a host distributed generation customer provides less revenue to the utility than it did prior to installing the distributed generation, it is also true that the host customer provides the utility with a source of very low-cost power.

The utilities' proposed solution is to increase fixed charges—at least for the customers who install distributed generation, and often for all customers. The higher fixed charges are proposed to ensure that customers with distributed generation continue to pay sufficient revenues to the utility, despite their reduced need for external generation.

<u>Response</u>

Concerns about potential cost-shifting from distributed generation resources are often dramatically overstated. While it is true that a host distributed generation customer provides less revenue to the utility than it did prior to installing the distributed generation, it is also true that the host customer provides the utility with a source of very low-cost power. The power from the distributed generation resource allows the utility to avoid the costs of generating, transmitting, and distributing electricity from its power plants. These avoided costs will put downward pressure on electricity rates, which will dramatically reduce or completely offset the upward pressure on rates created by the reduced revenues from the host customer.

This is a critical element of distributed generation resources that often is not recognized or fully addressed in discussions about alternative ratemaking options such as higher fixed charges. Unlike all other electricity resources, distributed generation typically provides the electric utility system with generation that is nearly free of cost to the utility and to other customers. This is because, in most instances, host customers pay for the installation and operation of the distributed generation system, with little or no payment required from the utility or other customers.[29]

One of the most important and meaningful indicators of the cost-effectiveness of an electricity resource is the impact that it will have on utility revenue requirements. The present value of revenue requirements (PVRR) is used in integrated resource planning practices throughout the United States as the primary criterion for determining whether an electricity resource is cost-effective and should be included in future resource plans.

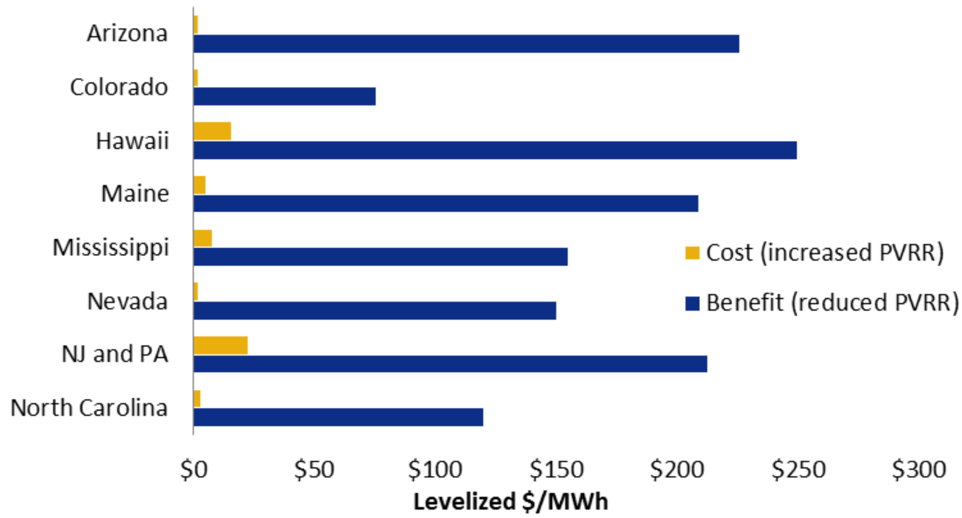
The benefits of distributed generation, in terms of reduced revenue requirements, will significantly reduce, and may even eliminate, any cost-shifting that might occur.

Several recent studies have shown that distributed generation resources are very cost-effective because they can significantly reduce revenue requirements by avoiding generation, transmission, and distribution costs, and only require a small increase in other utility expenditures. Figure 10 presents the benefits and costs of distributed generation according to six studies, where the benefits include all of the ways that distributed generation might reduce revenue requirements through avoided costs, and the costs include all of the ways that distributed generation might increase revenue requirements.[30] These costs typically include (a) the utility administrative costs of operating net energy metering programs, (b) the utility costs of interconnecting distributed generation technologies to the distribution grid, and (c) the utility costs of integrating intermittent distributed generation into the distribution grid.

[29] If a utility offers some form of an incentive to the host customer, such as a renewable energy credit, then this will represent an incremental cost imposed upon other customers. On the other hand, distributed generation customers provided with net energy metering practices do not require the utility or other customers to incur any new, incremental cost.

[30] Appendix C includes citations for these studies, along with notes on how the numbers in Figure 10 were derived.

Figure 10. Recent studies indicate the extent to which distributed generation benefits exceed costs



As indicated in the figure, all of these studies make the same general point: Distributed generation resources are very cost-effective in terms of reducing utility revenue requirements. In fact, they are generally more cost-effective than almost all other electricity resource options. The results presented in Figure 10 above indicate that distributed generation resources have benefit-cost ratios that range from 9:1 (New Jersey and Pennsylvania) to roughly 40:1 (Colorado, Maine, North Carolina) to as high as 113:1 (Arizona). These benefit-cost ratios are far higher than other electricity resource options, because the host customers typically pay for the cost of installing and operating the distributed generation resource.

Rate designs should be structured to encourage the development of very cost-effective resources, not to discourage them.

This point about distributed generation cost-effectiveness is absolutely essential for regulators and others to understand and acknowledge when making rate design decisions regarding distributed generation, for several reasons:

- The benefits of distributed generation, in terms of reduced revenue requirements, will significantly reduce, and may possibly even eliminate, any cost-shifting that might occur between distributed generation host customers and other customers.[31]

- When arguments about cost-shifting from distributed generation resources are used to justify increased fixed charges, it is important to assess and consider the likely magnitude of cost-shifting in light of the benefits offered by distributed generation. It is quite possible that any cost-shifting is *de minimis*, or non-existent.

- The net benefits of distributed generation should be considered as an important factor in making rate design decisions. Rate designs should be structured to encourage the

[31] This may not hold at very high levels of penetration, as integration costs increase once distributed generation levels hit a certain threshold. However, the vast majority of utilities in the United States have not yet reached such levels.

development of very cost-effective resources; they should not be designed to discourage them.

Again, policy makers should proceed with caution on claims regarding cost shifting. Where cost shifting is analyzed properly and found to be a legitimate concern, it can be addressed through alternative mechanisms that apply to DG customers, rather than upending the entire residential rate design in ways that can negatively affect all customers.

6. Recent Commission Decisions on Fixed Charges

Commission Decisions Rejecting Fixed Charges

Commissions in many states have largely rejected utility proposals to increase the fixed charge, citing a variety of reasons, including rate shock to customers and the potential to undermine state policy goals. Below are several reasons that commissions have given for rejecting such proposals.

Customer Control

In 2015, the Missouri Public Service Commission rejected Ameren's request to increase the residential customer charge, stating:

> The Commission must also consider the public policy implications of changing the existing customer charges. There are strong public policy considerations in favor of not increasing the customer charges. Residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power, either for economic reasons or because of a general desire to conserve energy. Leaving the monthly charge where it is gives the customer more control.[32]

Energy Efficiency, Affordability, and Other Policy Goals

The Minnesota Public Utilities Commission recently ruled against a relatively small increase in the fixed charge (from $8.00 to $9.25), citing affordability and energy conservation goals, as well as revenue regulation (decoupling) as a protection against utility under-recovery of revenues:

> In setting rates, the Commission must consider both ability to pay and the need to encourage energy conservation. The Commission must balance these factors against the requirement that the rates set not be "unreasonably preferential, unreasonably prejudicial, or discriminatory" and the utility's need for revenue sufficient to enable it to provide service.
>
> The Commission concludes that raising the Residential and Small General Service customer charges… would give too much weight to the fixed customer cost calculated in Xcel's class-cost-of-service study and not enough weight to affordability and energy conservation. … The Commission concurs with the OAG that this circumstance highlights the need for caution in making any decision that would further burden low-income, low-usage customers, who are unable to absorb or avoid the increased cost.

[32] Missouri Public Service Commission Report and Order, File No. ER-2014-0258, In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Revenues for Electric Service, April 29, 2015, pages 76-77.

> The Commission also concludes that a customer-charge increase for these classes would place too little emphasis on the need to set rates to encourage conservation. This is particularly true where the Commission has approved a revenue decoupling mechanism that will largely eliminate the relationship between Xcel's sales and the revenues it earns. As several parties have argued, decoupling removes the need to increase customer charges to ensure revenue stability.[33]

Similarly, in March of 2015, the Washington Utilities and Transportation Commission rejected an increase in the fixed charge based on concerns regarding affordability and conservation signals. The commission also reaffirmed that the fixed charge should only reflect costs directly related to the number of customers:

> We reject the Company's and Staff's proposals to increase significantly the basic charge to residential customers. The Commission is not prepared to move away from the long-accepted principle that basic charges should reflect only "direct customer costs" such as meter reading and billing. Including distribution costs in the basic charge and increasing it 81 percent, as the Company proposes in this case, does not promote, and may be antithetical to, the realization of conservation goals.[34]

In 2012, the Missouri Public Service Commission rejected Ameren Missouri's proposed increase in the customer charge for residential and small general service classes, writing:

> Shifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed customer charges, that cannot be reduced through energy efficiency efforts, will tend to reduce a customer's incentive to save electricity. Admittedly, the effect on payback periods associated with energy efficiency efforts would be small, but increasing customer charges at this time would send exactly [the] wrong message to customers that both the company and the Commission are encouraging to increase efforts to conserve electricity.[35]

In 2013, the Maryland Public Service Commission rejected a small increase in the customer charge, noting that such an increase would reduce customers' control of their bills and would be inconsistent with the state's policy goals.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the

[33] Minnesota Public Utilities Commission, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota; Findings of Fact, Conclusions, and Order; Docket No. E-002/GR-13-868, May 8, 2015, p. 88.

[34] Washington Utilities and Transportation Commission, Final Order Rejecting Tariff Sheets, Resolving Contested Issues, Authorizing And Requiring Compliance Filings; Docket UE-140762, March 25, 2015, p. 91.

[35] Missouri Public Service Commission, Report and Order, In the Matter of Union Electric Company Tariff to Increase Its Annual Revenues for Electric Service, File No. ER-2012-0166, December 12, 2012, pages 110-111.

> reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[36]

Commission Decisions Approving Higher Fixed Charges

Higher fixed charges have been rejected in numerous cases, but not all. In many cases, a small increase in the fixed charge has been approved through multi-party settlements, rather than addressed by the commission. Where commissions have specifically approved fixed charge increases, they often cite some of the flawed arguments that are addressed in Chapter 5 above. Below we provide some examples and briefly describe the commission's rationale.

Fixed Charges and Recovery of Distribution System Costs

Over the past few years, Wisconsin has approved some of the highest fixed charges in the country, based on the rationale that doing so will "prevent intra-class subsidies… provide appropriate price signals to ratepayers, and encourage efficient utility scale planning…."[37] This rationale is largely based on two misconceptions: (1) that short-run marginal costs provide an efficient price signal to ratepayers and will encourage efficient electric resource planning, and (2) that recovering certain distribution system costs through the fixed charge is more appropriate than recovering them through the energy charge.[38]

As discussed above, a rate design that fails to reflect long-run marginal costs will result in inefficient price signals to customers and ultimately result in the need to make more electric system investments to support growing demand than would otherwise be the case. Not only will growing demand result in the need for additional generation capacity, it may cause distribution system components to wear out faster, or to be replaced with larger components. Wrapping such costs up in the fixed charge sends the signal to customers that these costs are unavoidable, when in fact future investment decisions are in part determined by the level of system use.

Further, using the fixed charge to recover distribution system costs that cannot be readily classified as "demand-related" or "customer-related" exemplifies the danger that Bonbright warned of regarding using the category of customer costs as a "dumping ground" for costs that do not fit in the other

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36 In The Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates. Maryland Public Service Commission. Case No. 9299. Order No. 85374, Issued February 22, 2013, p. 99, provided in Schedule TW-4.

37 Docket 3270-UR-120, Order at 48.

38 For example, Wisconsin Public Service Corporation argued that the fixed charge should include a portion of the secondary distribution lines, line transformers, and the primary feeder system of poles, conduit and conductors, rather than only the customer-related costs.

categories. Use of the fixed charge for recovery of such costs tends to harm low-income customers, as well as distort efficient price signals.

Despite generally approving significantly higher fixed charges in recent years, in a December 2015 order the Wisconsin Public Service Commission approved only a slight increase in the fixed charge and signaled its interest in evaluating the impacts of higher fixed charges to ensure that the Commission's policy goals are being met. Specifically, the Commission directed one of its utilities to work with commission staff to conduct a study to assess the impacts of the higher fixed charges on customer energy use and other behavior.[39] This order indicates that perhaps the policy may be in need of further study.

Demand Costs Not Appropriate for Energy Charge

In approving Sierra Pacific Power's request for a higher fixed charge, the Nevada Public Service Commission wrote:

> If costs that do not vary with energy usage are recovered in the energy rate component, cost recovery is inequitably shifted away from customers whose energy usage is lower than average within their class, to customers whose energy usage is higher than average within that class. This is not just and reasonable.[40]

Despite declaring that demand-related costs are inappropriately recovered in the energy charge, the commission makes no argument for why the fixed charge is a more appropriate mechanism for recovering such costs. Nor does the commission recognize that customer demand (kW) and energy usage (kWh) are likely correlated, or that recovering demand-related costs in the fixed charge may introduce even greater cross-subsidies among customers.

Settlements

Many of the recent proceedings regarding fixed charges have ended in a settlement agreement. Several of these settlements have resulted in the intervening parties, including the utility, agreeing to make no change to the customer charge or fixed charge. For example, Kentucky Utilities and Louisville Gas & Electric requested a 67 percent increase in the fixed charge, from $10.75 to $18.00 per month. The case ultimately settled, with neither utility receiving an increase in the monthly fixed charge.[41] While

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[39] Wisconsin Public Service Commission, Docket 6690-UR-124, *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, Final Decision, December 17, 2015.

[40] Nevada Public Service Commission, Docket 13-06002, *Application of Sierra Pacific Power Company d/b/a NV Energy for Authority to Adjust its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto*, Modified Final Order, January 29, 2014, Page 176.

[41] Kentucky Public Service Commission Order, Case No. 2014-00372, *In the Matter of Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, page 4; Kentucky Public Service Commission Order, Case No. 2014-00371, *In the Matter of Application of Kentucky Utility Company for an Adjustment of Its Electric and Gas Rates*, page 4.

settlements seldom explicitly state the rationale behind such decisions, it is safe to expect that many of the settling parties echo the concerns stated by the Commissions above.

In conclusion, the push to significantly increase the fixed charge has largely been rejected by regulators across the country as unnecessary and poor public policy. Nevertheless, utilities continue to propose higher fixed charges, as any increase in the fixed charge helps to protect the utility from lower revenues associated with reduced sales, whether due to energy efficiency, distributed generation, or any other reason. In addition, in late 2015, it appeared that some utilities were beginning to propose new demand charges for residential customers instead of increased fixed charges.

7. Alternatives to Fixed Charges

Utilities are turning to higher fixed charges in an effort to slow the decline of revenues between rate cases, since revenue collected through the fixed charge is not affected by reduced sales. In the past, costs were relatively stable and sales between rate cases typically provided utilities with adequate revenue, but this is not necessarily the case anymore. The current environment of flat or declining sales growth, coupled with the need for additional infrastructure investments, can pose financial challenges for a utility and cause it to apply for rate cases more frequently.

Higher fixed charges are an understandable reaction to these trends, but they are an ill-advised remedy, due to the adverse impacts described above. Alternative rate designs exist that can help to address utility revenue sufficiency and volatility concerns, as discussed below. Furthermore, in many cases, utilities are reacting to perceived or future threats, rather than to a pressing current revenue deficiency. Simply stated, there is no need to increase the fixed charge.

Rate Design Options

Numerous rate design alternatives to higher fixed charges are available under traditional cost-of-service ratemaking. Below we discuss several of these options, and describe some of the key advantages and disadvantages of each. No prioritization of the options is implied, as rate design decisions should be made to address the unique circumstances of a particular jurisdiction. For example, the rate design adopted in Hawaii, where approximately 15 percent of residential customers on Oahu have rooftop solar,[42] may not be appropriate for a utility in Michigan.

[42] As of the third quarter of 2015, nearly 40,000 customers on Oahu were enrolled in the Hawaiian Electric Company's net metering program, as reported by HECO on its website: http://www.hawaiianelectric.com/heco/_hidden_Hidden/Community/Renewable-Energy?cpsextcurrchannel=1#05

Status Quo

One option is to simply maintain the current level of fixed charges and allow utilities to file frequent rate cases, if needed. This option is likely to be most appropriate where a utility is not yet facing any significant earnings shortfall, but is instead seeking to preempt what it views as a future threat to its earnings.

By maintaining the current rate structure rather than changing it prematurely, this option allows the extent of the problem to be more accurately assessed, and the remedy appropriately tailored to address the problem. Maintaining the current rate structure clearly also avoids the negative impacts on ratepayers and clean energy goals that higher fixed charges would have, as discussed in detail above.

However, maintaining the status quo may have detrimental impacts on both ratepayers and the utility if the utility is truly at risk of significant revenue under-recovery.[43] Where a utility cannot collect sufficient revenues, it may forego necessary investments in maintaining the electric grid or providing customer service, with potential long-term negative consequences.

In addition, the utility may file frequent rate cases in order to reset rates, which can be costly. Rate cases generally require numerous specialized consultants and lawyers to review the utility's expenditures and investments in great detail, and can drag on for months, resulting in millions of dollars in costs that could eventually be passed on to customers. Because of this cost, a utility is unlikely to file a rate case unless it believes that significantly higher revenues are likely to be approved.

Finally, chronic revenue under-recovery can worry investors, who might require a higher interest rate in order to lend funds to the utility. Since utilities must raise significant financial capital to fund their investments, a higher interest rate could ultimately lead to higher costs for customers. However, such chronic under-recovery is unlikely for most utilities, and this risk should be assessed alongside the risks of overcharging ratepayers and discouraging efficiency.

Minimum Bills

Minimum bills are similar to fixed charges, but with one important distinction: minimum bills only apply when a customer's usage is so low that his or her total monthly bill would otherwise be less than this minimum amount. For example, if the minimum bill were set at $40, and the only other charge was the energy charge of $0.10 per kWh, then the minimum bill would only apply to customers using less than 400 kWh, who would otherwise experience a bill less than $40. Given that the national average residential electricity usage is approximately 900 kWh per month, the minimum bill would have no effect on most residential customers.

[43] Of course, the claim that the utility is at risk of substantially under-recovering its revenue requirement should be thoroughly investigated before any action is taken.

A key advantage claimed by proponents to the minimum bill is that it guarantees that the utility will recover a certain amount of revenue from each customer, without significantly distorting price signals for the majority of customers. The threshold that triggers the minimum bill is typically set well below the average electricity usage level, and thus most customers will not be assessed a minimum bill but will instead only see the energy charge (cents per kilowatt-hour). Minimum bills also have the advantage of being relatively simple and easy to understand.

Minimum bills may be useful where there are many customers that have low usage, but actually impose substantial costs on the system. For example, this could include large vacation homes that have high usage during the peak summer hours that drive most demand-related costs, but sit vacant the remainder of the year. Unfortunately, minimum bills do not distinguish these types of customers from those who have reduced their peak demand (for example through investing in energy efficiency or distributed generation), and who thereby impose lower costs on the system.[44] Further, minimum bills may also have negative financial impacts on low-income customers whose usage falls below the threshold. For these reasons, minimum bills are superior to fixed charges, but they still operate as a relatively blunt instrument for balancing ratepayer and utility interests. Further, utilities will have an incentive to push for higher and higher minimum bill levels.

To illustrate the impacts of minimum bills, consider three rate options: (1) an “original” residential rate structure with a fixed charge of $9 per month; (2) a minimum bill option, which keeps the $9 fixed charge but adds a minimum bill of $40; and (3) an increase in the fixed charge to $25 per month. In all cases, the energy charge is adjusted to ensure that the three rate structures produce the same amount of total revenues. The figure below illustrates how moving from the “original” rate structure to either a minimum bill or increased fixed charge option would impact different customers.

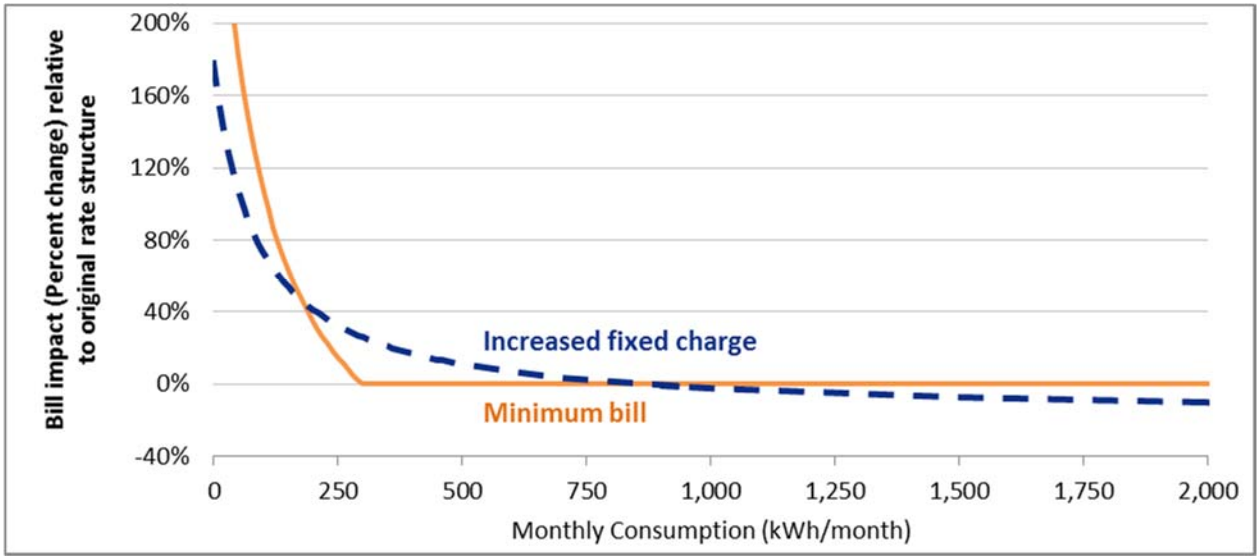
Under the minimum bill option, only customers with usage less than 280 kWh per month (approximately 5 percent of customers at a representative Midwestern utility) would see a change in their bills, and most of these customers would see an increase in their monthly bill of less than $10.

In contrast, under the $25 fixed charge, all customers using less than approximately 875 kWh per month (about half of residential customers) would see an increase in their electric bills, while customers using more than 875 kWh per month would see a *decrease* in their electric bills.

[44] In the short run, there is likely to be little difference in the infrastructure investments required to serve customers with high peak demands and those with low peak demands. However, in the long run, customers with higher peak demands will drive additional investments in generation, transmission, and distribution, thereby imposing greater costs on the system. A theoretically efficient price signal would reflect these different marginal costs in some manner in order to encourage customers to reduce the long-run costs they impose on the system.

Figure 11. Impact of minimum bill relative to an increased fixed charge

Rate Structure	Energy Charge	Fixed charge	Minimum bill
Typical rate structure	10.36 cents / kWh	$9 / Month	$0 / Month
Minimum bill	10.34 cents / kWh	$9 / Month	$40 / Month
Increased fixed charge	8.48 cents / kWh	$25 / Month	$0 / Month



Source: Author's calculations based on data from a representative Midwestern utility.

Time-of-Use Rates

Electricity costs can vary significantly over the course of the day as demand rises and falls, and more expensive power plants must come online to meet load.[45] Time-of-use (TOU) rates are a form of time-varying rate, under which electricity prices vary during the day according to a set schedule, which is designed to roughly represent the costs of providing electricity during different hours. A simple TOU rate would have separate rates for peak and off-peak periods, but intermediate periods may also have their own rates.

Time-varying rate structures can benefit ratepayers and society in general by improving economic efficiency and equity. Properly designed TOU rates can improve economic efficiency by:

1. Encouraging ratepayers to reduce their bills by shifting usage from peak periods to off-peak periods, thereby better aligning the consumption of electricity with the value a customer places on it;

2. Avoiding capacity investments and reducing generation from the most expensive peaking plants; and

[45] Electricity costs also vary by season and weekday/weekend.

3. Providing appropriate price signals for customer investment in distributed energy resources that best match system needs.

Time-varying rates are also capable of improving equity by better allocating the costs of electricity production during peak periods to those causing the costs.

Despite their advantages, TOU rates are not a silver bullet and may be inappropriate in the residential rate class. They may not always be easily understood or accepted by residential customers. TOU rates also require specialized metering equipment, which not all customers have. In particular, the adoption of advanced metering infrastructure (AMI) may impose significant costs on the system.[46] Residential consumers often do not have the time, interest or knowledge to manage variable energy rates efficiently, so TOU blocks must be few and well-defined and still may not elicit desired results. Designing TOU rates correctly can be difficult, and could penalize vulnerable customers requiring electricity during extreme temperatures. Some consumer groups (such as AARP) urge any such rates be voluntary. Finally, even well-designed TOU rates may not fully resolve a utility's revenue sufficiency concerns.

Value of Solar Tariffs

Value of solar tariffs pay distributed solar generation based on the value that the solar generation provides to the utility system (based on avoided costs). Value of solar tariffs have been approved as an alternative to net metering in Minnesota and in Austin, Texas. In both places, a third-party consultant conducted an avoided cost study (value of solar study) to determine the value of the avoided costs of energy, capacity, line losses, transmission and distribution.

Value of solar tariffs are useful in that they more accurately reflect cost causation, thereby improving fairness among customers. They also maintain efficient price signals that discourage wasteful use of energy, and improve revenue recovery and stability.

However, value of solar tariffs are not easily designed, as there is a lack of consensus on the elements that should be incorporated, how to measure difficult-to-quantify values, and even how to structure the tariff. Value of solar rates are also not necessarily stable, since value-of-solar tariff rates are typically adjusted periodically. However, there is no reason that the tariff couldn't be affixed for a set time period, like many long-term power purchase agreements.

Alternatively, if the value of solar is determined to be less than the retail price of energy, a rider or other charge could be implemented to ensure that solar customers pay their fair share of costs. Regardless of the type of charge or compensation mechanism chosen, a full independent, third-party analysis of the costs and benefits of distributed generation should be conducted prior to making any changes to rates.

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[46] AMI also allows remote disconnections and prepaid service options, both of which can disadvantage low-income customers. See, for example, Howat, J. *Rethinking Prepaid Utility Service: Customers at Risk.* National Consumer Law Center, June 2012.

Demand Charges

Generation, transmission, and distribution facilities are generally sized according to peak demands—either the local peak or the system peak. The peak demands are driven by the consumption levels of all electricity customers combined. Demand charges are designed to recover demand-related costs by charging electricity customers on the basis of maximum power demand (in terms of dollars per kilowatt), instead of energy (in terms of dollars per kilowatt-hour).

Designing rates to collect demand-related costs through demand charges may improve a utility's revenue recovery and stability. Proponents claim that such rates may also help send price signals that encourage customers to take steps to reduce their peak load. These charges have been in use for many years for commercial and industrial customers, but have rarely been implemented for residential customers.

Demand charges have several important shortcomings that limit how appropriate they might be for residential customers. First, demand charges remain relatively untested on the residential class. There is little evidence thus far that demand charges are well-understood by residential customers; instead, they would likely lead to customer confusion. This is particularly true for residential customers, who may be unaware of when their peak usage occurs and therefore have little ability or incentive to reduce their peak demand.

Second, depending on how they are set, demand charges may not accurately reflect cost causation. A large proportion of system costs are driven by system-wide peak demand, but the demand charge is often based on the customer's maximum demand (not the utility's). Thus demand charges do not provide an incentive for customers to reduce demand during the utility system peak in the way that time of use rates do. Theoretically, demand charges based on a customer's maximum demand could help reduce local peak demand, and therefore reduce some local distribution system costs. However, at the residential level, it is common for multiple customers to share a single piece of distribution system equipment, such as a transformer. Since a customer's maximum demand is typically triggered by a short period of time in which that customer is using numerous household appliances, it is unlikely that this specific time period coincides exactly when other customers sharing the same transformer are experiencing their maximum demands. This averaging out over multiple customers means that a single residential customer's maximum demand is not likely to drive the sizing of a particular piece of distribution-system equipment. For this reason, demand charges for the residential class are not likely to accurately reflect either system or local distribution costs.

Third, few options currently exist for residential customers to automatically monitor and manage their maximum demands. Since customer maximum monthly demand is often measured over a short interval of time (e.g., 15 minutes), a single busy morning where the toaster, microwave, hairdryer, and clothes dryer all happen to be operating at the same time for a brief period could send a customer's bill skyrocketing. This puts customers at risk for significant bill volatility. Unless technologies are implemented to help customers manage their maximum demands, demand charges should not be used.

Fourth, demand charges are not appropriate for some types of distributed generation resources. Some utilities have proposed that demand charges be applied to customers who install PV systems under net energy metering policies. This proposal is based on the grounds that demand charges will provide PV customers with more accurate price signals regarding their peak demands, which might be significantly different with customer-sited PV. However, a demand charge is not appropriate in this circumstance, because PV resources do not provide the host customer with any more ability to control or moderate peak demands than any other customer. A PV resource might shift a customer's maximum demand to a different hour, but it might do little to reduce the maximum demand if it occurs at a time when the PV resource is not operating much (because the maximum demand occurs either outside of daylight hours, or on a cloudy day when PV output is low).

Fifth, demand charges may require that utilities invest in expensive metering infrastructure and in-home devices that communicate information to customers regarding their maximum demands. The benefits of implementing a customer demand charge may not outweigh the costs of such investments.

In sum, most residential customers are very unlikely to respond to demand charges in a way that actually reduces peak demand, either because they do not have sufficient information, they do not have the correct price signal, they do not have the technologies available to moderate demand, or the technologies that they do have (such as PV) are not controllable by the customer in a way that allows them to manage their demand. In those instances where customers cannot or do not respond to demand charges, these charges suffer from all of the same problems of fixed charges: they reduce incentives to install energy efficiency or distributed generation; they pose an unfair burden on low-usage customers; they provide an inefficient price signal regarding long-term electricity costs; and they can eventually result in higher costs for all customers. For these reasons, demand charges are rarely implemented for residential customers, and where they have been implemented, it has only been on a voluntary basis.

8. CONCLUSIONS

In this era of rapid advancement in energy technologies and broad-based efforts to empower customers, mandatory fixed charges represent a step backward. Whether a utility is proposing to increase the fixed charge due to a significant decline in electricity sales or as a preemptive measure, higher fixed charges are an inequitable and economically inefficient means of addressing utility revenue concerns. In some cases, regulators and other stakeholders have been persuaded by common myths that inaccurately portray an increased fixed charge as the necessary solution to current challenges facing the utility industry. While they may be desirable for utilities, higher fixed charges are far from optimal for society as a whole.

Fortunately, there are many rate design alternatives that address utility concerns about declining revenues from lower sales without causing the regressive results and inefficient price signals associated with fixed charges. Recent utility commission decisions rejecting proposals for increased fixed charges suggest that there is a growing understanding of the many problems associated with fixed charges, and that alternatives do exist. As this awareness spreads, it will help the electricity system continue its progression toward greater efficiency and equity.

APPENDIX A – BONBRIGHT'S PRINCIPLES OF RATE DESIGN

In his seminal work, *Principles of Public Utility Rates*, Professor James Bonbright discusses eight key criteria for a sound rate structure. These criteria are:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the appointment of total costs of service among the different customers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company;
   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).[47]

[47] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291.

APPENDIX B – RECENT PROCEEDINGS ADDRESSING FIXED CHARGES

The tables below present data on recent utility proposals or finalized proceedings regarding fixed charges based on research conducted by Synapse Energy Economics. These cases were generally opened or decided between September 2014 and November 2015.

Table 1. List of finalized utility proceedings to increase fixed charges

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Alameda Municipal Power (CA)	AMP Board vote June 2015	$9.25	$11.50	$11.50	
Ameren (MO)	File No. ER - 2012-0166 Tariff No. YE-2014-0258	$8.00	$8.77	$8.00	Company initially proposed $12.00. Settling parties agreed to $8.77. Commission order rejected any increase, citing customer control
Appalachian Power Co (VA)	PUE-2014-00026	$8.35	$16.00	$8.35	
Appalachian Power/Wheeling Power (WV)	14-1152-E-42T	$5.00	$10.00	$8.00	
Baltimore Gas and Electric (MD)	9355, Order No. 86757	$7.50	$10.50	$7.50	Settlement based on Utility Law Judge
Benton PUD (WA)	Board approved in June 2015	$11.05	$15.60	$15.60	
Black Hills Power (WY)	20002-91-ER-14 (Record No. 13788)	$14.00	$17.00	$15.50	
Central Hudson Gas & Electric (NY)	14-E-0318	$24.00	$29.00	$24.00	
Central Maine Power Company (ME)	2013-00168	$5.71	$10.00	$10.00	Decoupling implemented as well
City of Whitehall (WI)	6490-ER-106	$8.00	$16.00	$16.00	
Columbia River PUD (OR)	CRPUD Board vote September 2015	$8.00	$20.45	$10.00	
Colorado Springs Utilities (CO)	City Council Volume No. 5	$12.52	$15.24	$15.24	
Connecticut Light & Power (CT)	14-05-06	$16.00	$25.50	$19.25	Active docket
Consolidated Edison (NY)	15-00270/15-E-0050	$15.76	$18.00	$15.76	Settlement
Consumers Energy (MI)	U-17735	$7.00	$7.50	$7.00	PSC Order
Choptank Electric Cooperative (MD)	9368, Order No. 86994,	$10.00	$17.00	$11.25	PSC approved smaller increase
Dawson Public Power (NE)	Announced June 2015	$21.50	$27.00	$27.00	Based on news articles
Empire District Electric (MO)	ER-2014-0351	$12.52	$18.75	$12.52	Settlement
Eugene Water & Electric Board (OR)	Board vote December 2014	$13.50	$20.00	$20.00	
Hawaii Electric Light (HI)	2014-0183	$9.00	$61.00	$9.00	Part of "DG 2.0"
Maui Electric Company (HI)	2014-0183	$9.00	$50.00	$9.00	Part of "DG 2.0"
Hawaii Electric Company (HI)	2014-0183	$9.00	$55.00	$9.00	Part of "DG 2.0"
Independence Power & Light Co (MO)	City Council vote September 2015	$4.14	$14.50	$4.14	Postponed indefinitely
Indiana Michigan Power (MI)	U-17698	$7.25	$9.10	$7.25	Settlement
Kansas City Power & Light (KS)	15-KCPE-116-RTS	$10.71	$19.00	$14.50	Settlement
Kansas City Power & Light (MO)	File No. ER-2014-0370	$9.00	$25.00	$11.88	
Kentucky Power (KY)	2014-00396	$8.00	$16.00	$11.00	Settlement was $14/month; PSC reduced to $11
Kentucky Utilities Company (KY)	2014-00371	$10.75	$18.00	$10.75	Settlement for KU LGE
Louisville Gas-Electric (KY)	2014-00372	$10.75	$18.00	$10.75	Settlement for KU LGE

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Madison Gas and Electric (WI)	3270-UR-120	$10.29	$22.00	$19.00	
Metropolitan Edison (PA)	R-2014-2428745	$8.11	$13.29	$10.25	Settlement
Nevada Power Co. (NV)	14-05004	$10.00	$15.25	12.75	Settlement
Northern States Power Company (ND)	PU-12-813	$9.00	$14.00	$14.00	Under previous rates, customers with underground lines paid $11/month
Pacific Gas & Electric Company (CA)	R.12-06-013, Rulemaking 12-06-013	$0.00	$10.00	$0.00	$10 minimum bill adopted instead
PacifiCorp (WA)	UE-140762	$7.75	$14.00	$7.75	Commission order emphasized customer control
Pennsylvania Electric (PA)	R-2014-2428743	$7.98	$11.92	$9.99	Settlement
Pennsylvania Power (PA)	R-2014-2428744	$8.86	$12.71	$10.85	Settlement
Redding Electric Utility (CA)	City Council Meeting June 2015	$13.00	$42.00	$13.00	Postponed consideration until 2/2017
Rocky Mountain Power (UT)	13-035-184	$5.00	$8.00	$6.00	Settlement
Rocky Mountain Power (WY)	20000-446-ER-14 (Record No. 13816)	$20.00	$22.00	$20.00	
Salt River Project (AZ)	SRP Board vote February 2015	$17.00	$20.00	$20.00	Elected board of SRP voted Feb. 26 2015
San Diego Gas & Electric (CA)	A.14-11-003 & R.12-06-013, Rulemaking 12-06-013	$0.00	$10.00	$0.00	$10 minimum bill adopted instead
Sierra Pacific Power (NV)	13-06002, 13-06003, 13-06004	$9.25	$15.25	$15.25	
Southern California Edison (CA)	A.13-11-003 & R.12-06-013, Rulemaking 12-06-013	$0.94	$10.00	$0.94	$10 minimum bill adopted instead
Stoughton Utilities (W()	5740-ER-108	$7.50	$10.00	$10.00	
We Energies (WI)	5-UR-107	$9.13	$16.00	$16.00	
West Penn Power (PA)	R-2014-2428742	$5.00	$7.35	$5.81	Settlement
Westar (KS)	15-WSEE-115-RTS	$12.00	$27.00	$14.50	Settlement
Wisconsin Public Service (MI)	U-17669	$9.00	$12.00	$12.00	Settlement
Wisconsin Public Service (WI)	6690-UR-123	$10.40	$25.00	$19.00	
Xcel Energy (MN)	E002 / GR-13-868	$8.00	$9.25	$8.00	Commission order emphasized customer control

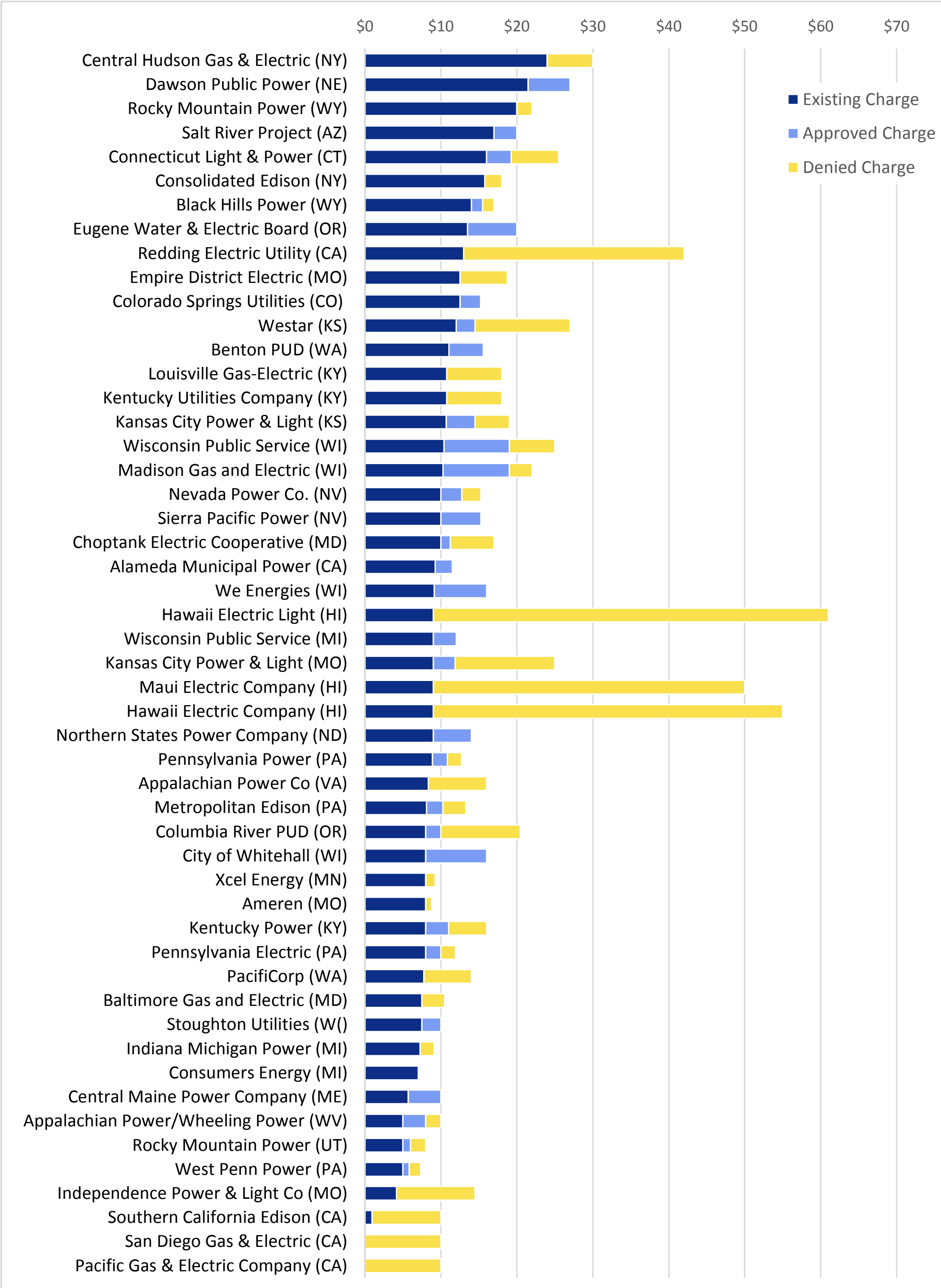
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

Table 2. Pending dockets and proposals to increase fixed charges

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Avista Utilities (ID)	AVU-E-15-05	$5.25	$8.50		Active docket
Avista Utilities (WA)	UE-150204	$8.50	$14.00		
Detroit Edison (MI)	U-17767	$6.00	$10.00		Proposed order has rejected residential increase
El Paso Electric (TX)	44941	$7.00	$10.00		Public hearings ongoing
El Paso Electric (NM)	15-00127-UT	$5.04	$10.04		Public hearings ongoing
Entergy Arkansas, Inc. (AR)	15-015-U	$6.96	$9.00		Active docket
Indianapolis Power & Light (IN)	44576/44602	$11.00	$17.00		Active docket, values reflect proposal for customers that use more than 325 kWh
Lincoln Electric System (NE)	City council proceeding	$11.15	$13.40		City council decision is pending
Long Island Power Authority (NY)	15-00262	$10.95	$20.38		Rejected by PSC, LIPA Board has ultimate decision
Montana-Dakota Utilities (MT)	D2015.6.51	$5.48	$7.60		BSC based on per day not per month, values converted to monthly
National Grid (MA)	D.P.U. 15-120	$4.00	$13.00		Proposed as part of Grid Mod plan, presented as "Tier 3" customer, for use between 601 to 1,200 kWh per month
National Grid (RI)	RIPUC DOCKET NO. 4568	$5.00	$13.00		Presented as "Tier 3" customer, for use between 751 to 1,200 kWh per month
NIPSCO (IN)	44688	$11.00	$20.00		Active Docket
Omaha Public Power District (NE)	Public power	$10.25	$30.00		Based on news coverage of stakeholder meetings. No specific number submitted, $20, $30, $35 where floated past stakeholders
PECO (PA)	R-2015-2468981	$7.12	$12.00	$8.45	Settlement not yet ratified
Public Service Company of New Mexico (NM)	15-00261-UT	$5.00	$13.14		Public hearings ongoing
Portland General Electric (OR)	UE 294	$10.00	$11.00		Proposed
Pennsylvania Power and Light (PA)	R-2015-2469275	$14.09	$20.00	$14.09	Settlement not yet ratified
Santee Cooper (SC)	State utility	$14.00	$21.00		Pending, expected decision in December 2015
Springfield Water Power and Light (IL)	Municipal board	$5.76	$12.87		Pending as of Oct 1 2015
Sulfur Springs Valley Electric Coop (AZ)	E-01575A-15-0312	$10.25	$25.00		Active docket
Sun Prairie Utilities (WI)	5810-ER-106	$7.00	$16.00		
UNS Electric Inc. (AZ)	E-04204A-15-0142	$10.00	$20.00		Active docket, hearings in March 2016
Xcel Energy (WI)	4220-UR-121	$8.00	$18.00		

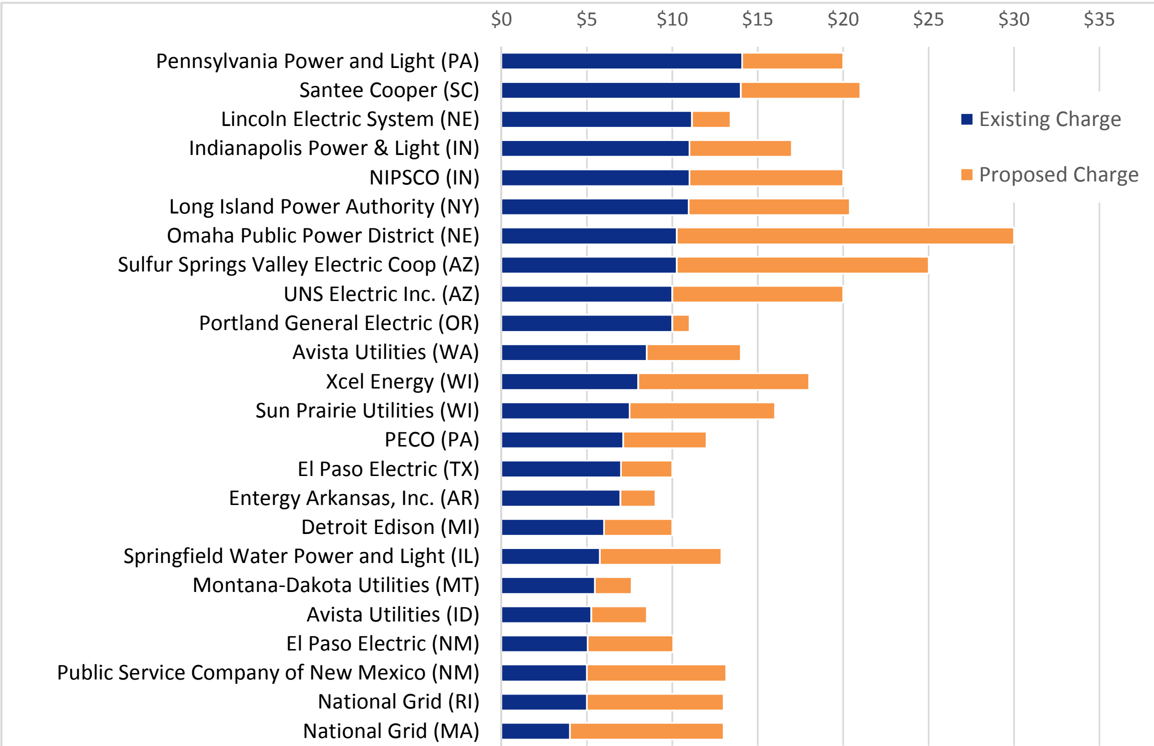
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

Figure 12. Finalized decisions of utility proceedings to increase fixed charges



Notes: Denied includes settlements that did not increase the fixed charge.

Figure 13. Existing and proposed fixed charges of utilities with pending proceedings to increase fixed charges

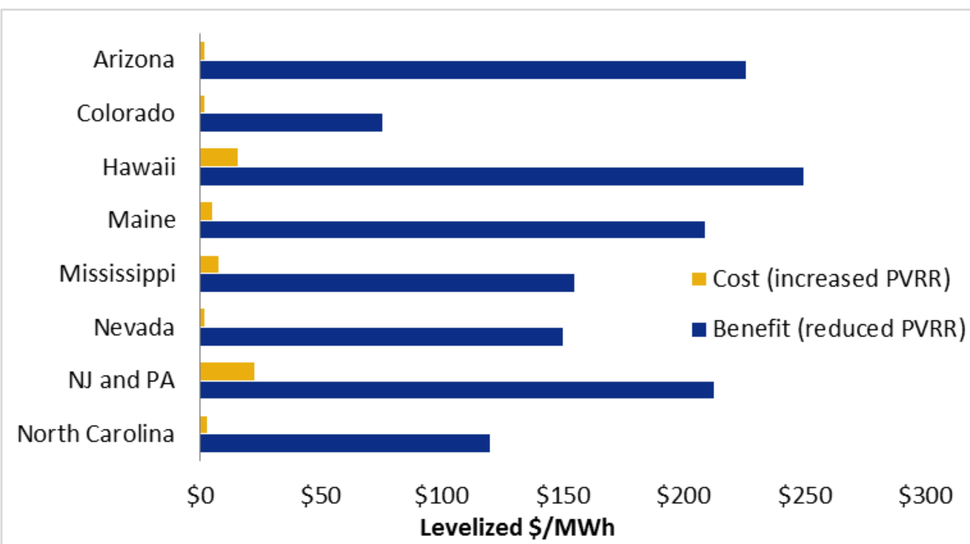


APPENDIX C – NET METERING IMPACTS ON UTILITY COSTS

A utility's revenue requirement represents the amount of revenue that it must recover from customers to cover the costs of serving customers (plus a return on its investments). Customers who invest in distributed PV may increase certain costs while reducing others. Costs associated with integration, administration, and interconnection of net energy metered (NEM) systems will increase revenue requirements, and thus are considered a cost. At the same time, a NEM system will avoid other costs for the utility, such as energy, capacity, line losses, etc. These avoided costs will reduce revenue requirements, and thus are a benefit. These costs and benefits over the PV's lifetime can be converted into present value to determine the impact on the utility's present value of revenue requirements (PVRR).

Over the past few years, at least eight net metering studies have quantified the impact of NEM on a utility's revenue requirement. Key results from these studies are summarized in the table and figure below. Note that only those costs and benefits that affect revenue requirements are included as costs or benefits. If a study included benefits that do not affect revenue requirements (such as environmental externality costs, reduced risk, fuel hedging value, economic development, and job impacts), then they were subtracted from the study results. Similarly, the costs presented below include only NEM system integration, interconnection, and administration costs.[48] Other costs that are sometimes included in the studies but do not affect revenue requirements, such as lost revenues, are not included.

Figure 14. Recent studies indicate extent to which NEM benefits exceed costs



[48] Historically, some utilities have offered incentives to customers that install solar panels (or other NEM installations). While these incentive payments do put upward pressure on revenue requirements, the incentives themselves are removed from Figure 14 and Table 3 to help compare costs and benefits when utility-specific incentives are taken out of the equation.

Table 3. Net metering studies that report PVRR benefits and costs

Year	State	Funded / Commissioned by	Prepared by	Benefit ($/MWh)	Cost ($/MWh)	Benefit-Cost Ratio
2013	Arizona	---------	Crossborder Energy	226*	2	113
2013	Colorado	Xcel Energy	Xcel Energy	75.6	1.8	42
2014	Hawaii	HI PUC	E3	250*	16	16
2015	Maine	Maine Public Utilities Commission	Clean Power Research, et. al.	209	5	42
2014	Mississippi	Mississippi Public Service Commission	Synapse Energy Economics	155	8	19
2014	Nevada	State of Nevada Public Utilities Commission	E3	150	2	75
2012	NJ and PA	Mid-Atlantic Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association	Clean Power Research	213*	23*	9
2013	North Carolina	NC Sustainable Energy Association	Crossborder Energy	120*	3	40

**Indicates that the value displayed in the table is the midpoint of the high and low values reported in the study.*

Source: Synapse Energy Economics, 2015.

Arizona

The Arizona study, performed by Crossborder Energy, presents 20-year levelized values in 2014 dollars.[49] Benefits include avoided energy, generation capacity, ancillary services, transmission, distribution, environmental compliance, and costs of complying with renewable portfolio standards. The avoided environmental benefits account for non-CO_2 market costs of NO_X, SO_X, and water treatment costs, and thus are included as revenue requirement benefits. The benefits range from $215 per MWh to $237 per MWh. Figure 14 and Table 3 present the midpoint value of this range: $226 per MWh. The report estimates integration costs to be $2 per MWh.

Colorado

The Colorado study, performed by the utility Xcel Energy, presents 20-year levelized net avoided costs under three cases in the report's Table 1.[50] The benefits include avoided energy, emissions, capacity, distribution, transmission and line losses. The benefits also include an avoided hedge value, which does not affect revenue requirements. Removing the hedge value from the benefits yields a revenue

[49] Crossborder Energy. 2013. The Benefits and Costs of Solar Distributed Generation for Arizona Public Service. Page 2. Table 1.

[50] Xcel Energy. 2013. Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System. Executive Summary, page V.

requirement benefit of $75.6 per MWh. The study estimates solar integration costs to be $1.80 per MWh.

Hawaii

The Hawaii study, performed by E3, presents the 20-year levelized costs and benefits of NEM on the various Hawaii utilities (HECO, MECO, HELCO, and KIUC). The base case NEM benefits are $213 per MWh for KIUC,[51] $234 per MWh for MECO,[52] $242 per MWh for HELCO,[53] and $287 for HECO.[54] Figure 14 and Table 3 present the midpoint of these values: $250 per MWh. The NEM revenue requirement costs are estimated to be $16 per MWh, which includes integration costs ($6 per MWh) and transmission and distribution interconnection costs ($10 per MWh).[55]

Maine

The Maine study, prepared by several co-authors, presents the 25-year levelized market and societal benefits for Central Maine Power Company.[56] The revenue requirement benefits, including avoided costs and market price response benefits, are $209 per MWh. The study estimates the NEM revenue requirement costs to be $5 per MWh, reflecting NEM system integration costs.

Mississippi

The Mississippi study, prepared by Synapse Energy Economics, presents base case 25-year levelized benefits associated with avoided energy, capacity, transmission and distribution, system losses, environmental compliance costs, and risk.[57] The total revenue requirements benefit is $155 per MWh, which excludes the $15 per MWh risk benefit. The NEM administrative costs are estimated to be $8 per MWh.

Nevada

The Nevada study, conducted by E3, presents costs and benefits on a 25-year levelized basis in 2014 dollars. The study estimates the costs and benefits for several “vintages” of rooftop solar. Figure 14 and Table 3 present the vintage referred to as “2016 installations,” because this is most representative of

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[51] E3, Evaluation of Hawaii’s Renewable Energy Policy and Procurement, January 2014, page 53, Figure 26.

[52] Ibid. Page 50, Figure 23.

[53] Ibid. Page 47, Figure 20.

[54] Ibid. Page 43, Figure 17.

[55] Ibid. Pages 55 and 56.

[56] Clean Power Research, Sustainable Energy Advantage, & Pace Law School Energy and Climate Center for Maine PUC. 2015. *Maine Distributed Solar Valuation Study*. Page 50. Figure 7.

[57] Synapse Energy Economics for Mississippi PSC. 2014. *Net Metering in Mississippi*. Pages 33 and 38.

costs and benefits in the future. The revenue requirement benefits, including avoided costs and renewable portfolio standard value, are estimated to be $150 per MWh. The E3 study also reports the "incentive, program, and integration costs" to be $6 per MWh.[58] This value includes the integration costs, which were assumed by E3 to be $2 per MWh.[59] Customer incentive costs are not included in any of the results presented in Figure 14 and Table 3, so the revenue requirement costs for Nevada include only the integration costs of $2 per MWh.

New Jersey and Pennsylvania

The New Jersey and Pennsylvania study, prepared by several co-authors, presents the 30-year levelized value of solar for seven locations.[60] The benefits include energy benefits (that would contribute to reduced revenue requirements), strategic benefits (that may not contribute to reduced revenue requirements), and other benefits (some of which would contribute to reduced revenue requirements). To determine the revenue requirement benefits, the benefits associated with "security enhancement value," "long term societal value," and "economic development value" are excluded. The highest reported benefit value was in Scranton ($243 per MWh) and the lowest value was reported in Atlantic City ($183 per MWh). Figure 14 and Table 3 present the midpoint of these two values: $213 per MWh. Similarly, they present the midpoint of the solar integration costs ($23 per MWh).

North Carolina

The North Carolina study, prepared by Crossborder Energy, presents 15-year levelized values in 2013 dollars per kWh. The benefits are presented for three utilities separately. A high/low range of benefits were presented for each benefit category (energy, line losses, generation capacity, transmission capacity, avoided emissions, and avoided renewables). The low avoided emissions estimate reflects the costs of compliance with environmental regulations, which will affect revenue requirements, but the high avoided emissions estimate reflects the social cost of carbon, which will not affect revenue requirements. Therefore, the low avoided emissions value ($4 per MWh) is included, but the incremental social cost of carbon value ($18 per MWh) is excluded. The lowest revenue requirement benefit presented in the study is $93 per MWh for DEP, and the highest one is $147 per MWh for DNCP (after removing the incremental social cost of carbon). Figure 14 and Table 3 present the midpoint between the high and low values, $120 per MWh, as the revenue requirement benefit. The study also identifies $3 per MWh in revenue requirement costs.

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[58] E3 for Nevada PUC. 2014. *Nevada Net Energy Metering Impacts Evaluation*. Page 96.

[59] Ibid. Page 61.

[60] Clean Power Research for Mid-Atlantic & Pennsylvania Solar Energy Industries Associations. 2012. *The Value of Distributed Solar Electric Generation to NJ and PA*. Page 18.

GLOSSARY

Advanced Metering Infrastructure (AMI): Meters and data systems that enable two-way communication between customer meters and the utility control center.

Average Cost: The revenue requirement divided by the quantity of utility service, expressed as a cost per kilowatt-hour or cost per therm.

Average Cost Pricing: A pricing mechanism basing the total cost of providing electricity on the accounting costs of existing resources. (See Marginal Cost Pricing, Value-Based Rates.)

Capacity: The maximum amount of power a generating unit or power line can provide safely.

Classification: The separation of costs into demand-related, energy-related, and customer-related categories.

Coincident Peak Demand: The maximum demand that a load places on a system at the time the system itself experiences its maximum demand.

Cost-Based Rates: Electric or gas rates based on the actual costs of the utility (see Value-Based Rates).

Cost-of-Service Regulation: Traditional electric utility regulation, under which a utility is allowed to set rates based on the cost of providing service to customers and the right to earn a limited profit.

Cost-of-Service Study: A study that allocates the costs of a utility between the different customer classes, such as residential, commercial, and industrial. There are many different methods used, and no method is "correct."

Critical Period Pricing or Critical Peak Pricing (CPP): Rates that dramatically increase on short notice when costs spike, usually due to weather or to failures of generating plants or transmission lines.

Customer Charge: A fixed charge to consumers each billing period, typically to cover metering, meter reading, and billing costs that do not vary with size or usage. Sometimes called a Basic Charge or Service Charge.

Customer Class: A group of customers with similar usage characteristics, such as residential, commercial, or industrial customers.

Decoupling: A regulatory design that breaks the link between utility revenues and energy sales, typically by a small periodic adjustment to the rate previously established in a rate case. The goal is to match actual revenues with allowed revenue, regardless of sales volumes.

Demand: The rate at which electrical energy or natural gas is used, usually expressed in kilowatts or megawatts, for electricity, or therms for natural gas.

Demand Charge: A charge based on a customer's highest usage in a one-hour or shorter interval during a certain period. The charge may be designed in many ways. For example, it may be based on a customer's maximum demand during a monthly billing cycle, during a seasonal period, or during an annual cycle. In addition, some demand charges only apply to a customer's maximum demand that coincides with the system peak, or certain peak hours. Typically assessed in cents per kilowatt.

Distribution: The delivery of electricity to end users via low-voltage electric power lines (usually 34 kV and below).

Embedded Costs: The costs associated with ownership and operation of a utility's existing facilities and operations. (See Marginal Cost.)

Energy Charge: The part of the charge for electric service based upon the electric energy consumed or billed (i.e., cents per kilowatt-hour).

Fixed Cost: Costs that the utility cannot change or control in the short-run, and that are independent of usage or revenues. Examples include interest expense and depreciation expense. In the long run, there are no fixed costs, because eventually all utility facilities can be retired and replaced with alternatives.

Flat Rate: A rate design with a uniform price per kilowatt-hour for all levels of consumption.

Fully Allocated Costs or Fully Distributed Costs: A costing procedure that spreads the utility's joint and common costs across various services and customer classes.

Incentive Regulation: A regulatory framework in which a utility may augment its allowed rate of return by achieving cost savings or other goals in excess of a target set by the regulator.

Incremental Cost: The additional cost of adding to the existing utility system.

Inverted Rates/Inclining Block Rates: Rates that increase at higher levels of electricity consumption, typically reflecting higher costs of newer resources, or higher costs of serving lower load factor loads such as air conditioning. Baseline and lifeline rates are forms of inverted rates.

Investor-Owned Utility (IOU): A privately owned electric utility owned by and responsible to its shareholders. About 75% of U.S. consumers are served by IOUs.

Joint and Common Costs: Costs incurred by a utility in producing multiple services that cannot be directly assigned to any individual service or customer class; these costs must be assigned according to some rule or formula. Examples are distribution lines, substations, and administrative facilities.

Kilowatt-Hour (kWh): Energy equal to one thousand watts for one hour.

Load Factor: The ratio of average load to peak load during a specific period of time, expressed as a percent.

Load Shape: The distribution of usage across the day and year, reflecting the amount of power used in low-cost periods versus high-cost periods.

Long-Run Marginal Costs: The long-run costs of the next unit of electricity produced, including the cost of a new power plant, additional transmission and distribution, reserves, marginal losses, and administrative and environmental costs. Also called long-run incremental costs.

Marginal Cost Pricing: A system in which rates are designed to reflect the prospective or replacement costs of providing power, as opposed to the historical or accounting costs. (See Embedded Cost.)

Minimum Charge: A rate-schedule provision stating that a customer's bill cannot fall below a specified level. These are common for rates that have no separate customer charge.

Operating Expenses: The expenses of maintaining day-to-day utility functions. These include labor, fuel, and taxes, but not interest or dividends.

Public Utility Commission (PUC): The state regulatory body that determines rates for regulated utilities. Sometimes called a Public Service Commission or other names.

Rate Case: A proceeding, usually before a regulatory commission, involving the rates and policies of a utility.

Rate Design: The design and organization of billing charges to distribute costs allocated to different customer classes.

Short Run Marginal Cost: Only those variable costs that change in the short run with a change in output, including fuel; operations and maintenance costs; losses; and environmental costs.

Straight Fixed Variable (SFV) Rate Design: A rate design method that recovers all short-run fixed costs in a fixed charge, and only short-run variable costs in a per-unit charge.

Time-of-Use Rates: A form of time-varying rate. Typically the hours of the day are segmented to "off-peak" and "peak" periods. The peak period rate is higher than the off-peak period rate.

Time-Varying Rates: Rates that vary by time of day in order to more accurately reflect the fluctuation of costs. A common, and simple form of time-varying rate is time-of-use rates.

Variable Cost: Costs that vary with usage and revenue, plus costs over which the utility has some control in the short-run, including fuel, labor, maintenance, insurance, return on equity, and taxes. (See Short Run Marginal Cost.)

Volumetric Rate: A rate or charge for a commodity or service calculated on the basis of the amount or volume actually received by the customer (e.g., cents/kWh, or cents/kW). May also be referred to as the "variable rate." If referring to cents per kilowatt-hour, it is often referred to as the "energy charge."

Adapted from Lazar (2011) "Electricity Regulation in the US: A Guide." Regulatory Assistance Project.

Assumptions (Proposed Rates)

Current Base Charge	$20.39	per month
Current Energy Charge	$0.05619	per kWh
Proposed Base Charge	$48.09	per month
Proposed Energy Charge	$0.03298	per kWh
Fuel	$0.03163	per kWh
Capacity	$0.00888	per kWh
ECRC	$0.02158	per kWh
ECCR	$0.00160	per kWh
Clauses	$0.06369	per kWh
Residential Price Elasticity	-0.253	

Annual Energy	Avg Annual kWh/Cust	Avg Monthly kWh/Cust	% of Total Cust	Number of Customers	Annual GWh	Est. Monthly kWh/Cust	Est. Annual GWh
0K-2K	802	67	4.7%	18,748	15	51	12
2K-4K	2,824	235	4.2%	16,669	47	208	42
4K-6K	4,972	414	5.2%	20,827	104	387	97
6K-8K	7,245	604	4.2%	16,669	121	581	116
8K-10K	8,990	749	16.2%	64,559	580	731	567
10K-12K	11,139	928	17.7%	70,795	789	917	779
12K-14K	13,212	1,101	9.4%	37,496	495	1,097	494
14K-16K	15,122	1,260	6.8%	27,063	409	1,263	410
16K-18K	17,055	1,421	5.7%	22,905	391	1,431	393
18K-20K	18,932	1,578	9.4%	37,496	710	1,595	718
20K-22K	20,736	1,728	4.2%	16,669	346	1,752	350
22K-24K	23,043	1,920	3.1%	12,512	288	1,953	293
24K-26K	24,803	2,067	4.2%	16,669	413	2,106	421
26K-28K	26,454	2,205	0.5%	2,079	55	2,250	56
28K-30K	28,405	2,367	1.6%	6,236	177	2,421	181
30K-32K	31,175	2,598	1.0%	4,157	130	2,662	133
32K-34K	32,973	2,748	0.5%	2,079	69	2,819	70
36K-38K	36,536	3,045	1.0%	4,157	152	3,131	156
>38k	38,563	3,214	0.5%	2,079	80	3,308	83
		Total	**100.0%**	**399,746**	**5,370**		**5,371**

Change in Energy 0.7 GWh

Note: The 34k-36k annual energy group did not have any customers.

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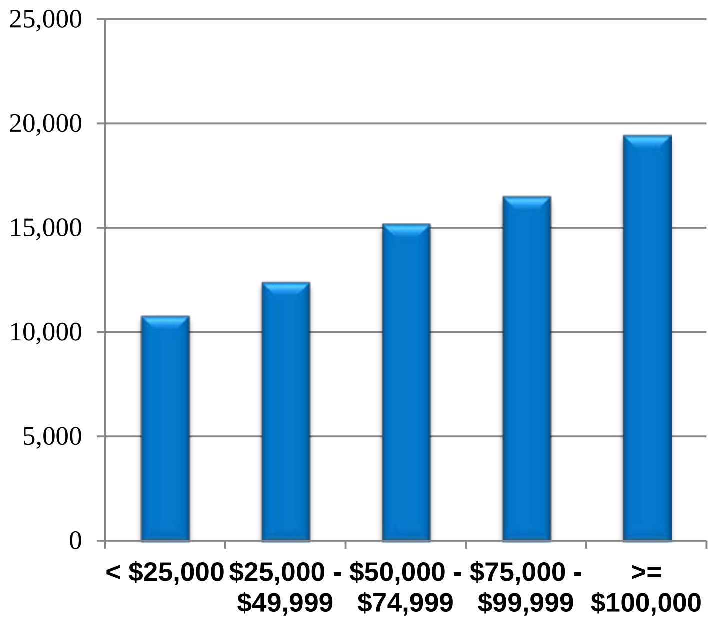
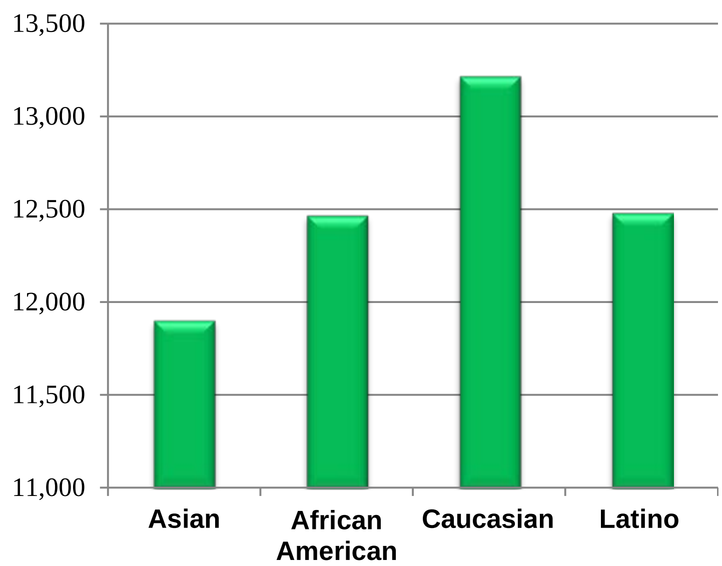
Utility Rate Design:
How Mandatory Monthly Customer Fees Cause Disproportionate Harm

U.S. Region: FL

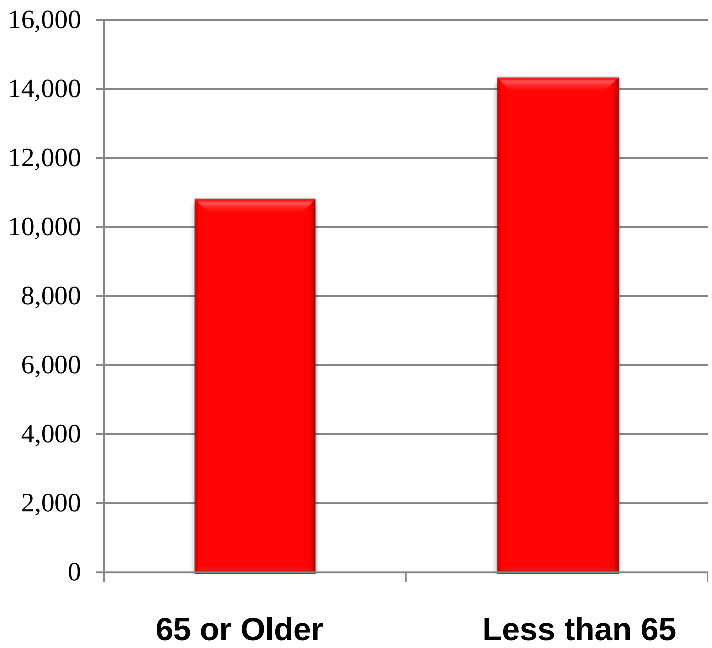
Median 2009 Residential Electricity Usage (KWH), by Income



Median 2009 Residential Electricity Usage (KWH), by Race/Ethnicity



Median 2009 Residential Electricity Usage (KWH), by Age



2009 Residential Energy Consumption by Income, Race/Ethnicity, & Age

HOUSEHOLD INCOME	MEDIAN ELECTRICITY USAGE (KWH)
< $25,000	10,819
$25,000 - $49,999	12,419
$50,000 - $74,999	15,215
$75,000 - $99,999	16,536
>=$100,000	19,467

HOUSEHOLD RACE	MEDIAN ELECTRICITY USAGE (KWH)
Asian	11,905
African American	12,469
Caucasian	13,219
Latino	12,483

HOUSEHOLD AGE	MEDIAN ELECTRICITY USAGE (KWH)
65 years or older	10,834
Less than 65 years	14,346

Source: U.S. Energy Information Administration's Residential Energy Consumption Survey, 2009 (most recent data available)

For questions, contact John Howat: jhowat@nclc.org | 617-542-8010

Robert L. McGee, Jr.
Regulatory & Pricing Manager

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GULF POWER
A SOUTHERN COMPANY

March 31, 2014

Mr. Jim Dean, Director
Division of Economics
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee FL 32399-0868

Dear Mr. Dean:

Attached are six revised pages (53 through 58) of Gulf Power Company's 2013 Annual FEECA Program Progress Report initially submitted on February 28, 2014. The revisions are for the years 2011 – 2013 for the Residential Solar Thermal, Residential Solar PV, and the Commercial Solar PV programs. These revisions are carried forward to the Savings at the Meter, Savings at the Generator, and the Comparison of Achieved kW and kWh Reductions summary schedules. The revised data is highlighted in green for ease of identification.

If you have any questions, please do not hesitate to give me a call.

Sincerely,

Robert L. McGee, Jr.

Robert L. McGee, Jr.
Regulatory and Pricing Manager

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Attachments

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Solar Thermal

Program Start Date: June, 2011

Reporting Period: Annual 2013

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2010	374,936	373,219	115	0.03%	...	...	...	...
2011	377,336	375,619	230	0.06%	47	47	0.01%	(183)
2012	381,544	379,827	345	0.09%	36	83	0.02%	(262)
2013	388,378	386,661	460	0.12%	23	106	0.03%	(354)
2014	396,913	395,196	575	0.15%				
2015	405,062	403,345	575	0.14%				
2016	413,491	411,774	575	0.14%				
2017	421,774	420,057	575	0.14%				
2018	430,056	428,339	575	0.13%				
2019	438,190	436,473	575	0.13%				

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.25	0.33	5.75	7.59
Summer kW Reduction	0.25	0.33	5.75	7.59
Annual kWh Reduction	1,906	2,078	43,838.00	47,794.00

	Annual
Utility Cost per Installation:	$3,109
Total Program Cost of the Utility ($000):	$72
Net Benefits of Measures Installed During Reporting Period:	N/A

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Solar PV

Program Start Date: June, 2011

Reporting Period: Annual 2013

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2010	374,936	373,219	40	0.01%	...	...	...	...
2011	377,336	375,619	80	0.02%	41	41	0.01%	(39)
2012	381,544	379,827	120	0.03%	44	85	0.02%	(35)
2013	388,378	386,661	160	0.04%	42	127	0.03%	(33)
2014	396,913	395,196	200	0.05%				
2015	405,062	403,345	200	0.05%				
2016	413,491	411,774	200	0.05%				
2017	421,774	420,057	200	0.05%				
2018	430,056	428,339	200	0.05%				
2019	438,190	436,473	200	0.05%				

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	1.50	1.97	63.00	82.74
Summer kW Reduction	3.00	3.94	126.00	165.48
Annual kWh Reduction	6,388	6,963	268,296.00	292,446.00

	Annual
Utility Cost per Installation:	$3,878
Total Program Cost of the Utility ($000):	$163
Net Benefits of Measures Installed During Reporting Period:	N/A

Docket No. 160186-EI
2013 Annual FEECA Program
Exhibit KRR-13, Page 3 of 7

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Solar PV

Program Start Date: June, 2011

Reporting Period: Annual 2013

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2010	54,648	46,618	6	0.01%	...	...	...	...
2011	55,016	46,872	12	0.03%	1	1	0.00%	(11)
2012	55,584	47,317	18	0.04%	3	4	0.01%	(14)
2013	56,431	48,039	24	0.05%	3	7	0.01%	(17)
2014	57,460	48,940	30	0.06%				
2015	58,450	49,802	30	0.06%				
2016	59,469	50,692	30	0.06%				
2017	60,476	51,568	30	0.06%				
2018	61,486	52,443	30	0.06%				
2019	62,491	53,302	30	0.06%				

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	1.50	1.97	4.50	5.91
Summer kW Reduction	3.00	3.94	9.00	11.82
Annual kWh Reduction	6,388	6,963	19,164.00	20,889.00

	Annual
Utility Cost per Installation:	$27,626
Total Program Cost of the Utility ($000):	$83
Net Benefits of Measures Installed During Reporting Period:	N/A

Docket No. 160186-EI
2013 Annual FEECA Program
Exhibit KRR-13, Page 4 of 7

GULF POWER COMPANY

2013 DSM Progress Report
Savings at the Meter
2010 DSM PLAN

Residential Programs	Measures	A Total Units	B Per Unit Win. kW	C Per Unit Sum. kW	D Per Unit kWh	E Total Win. MW	F Total Sum. MW	G Total GWh	H Cumulative Win. MW	I Cumulative Sum. MW	J Cumulative GWh
Residential Energy Audit and Education	Home Energy Reporting	39,171	0.06	0.06	300	2.35	2.35	11.75	2.35	2.35	11.75
Community Energy Saver	Residential Community Energy Saver	2,220	0.11	0.05	736	0.24	0.11	1.63	0.82	0.37	5.40
Landlord/Renter Custom Incentive	Landlord/Renter Customer Incentive Program	0	----	----	----	0.00	0.00	0.00	0.00	0.12	0.29
HVAC Efficiency Improvement	Residential HVAC Maintenance	11,344	0.26	0.31	1,300	2.95	3.52	14.82	5.45	6.49	27.33
HVAC Efficiency Improvement	Residential HVAC Early Retirement Tier 1	1,251	1.16	1.24	5,854	1.45	1.55	7.32	2.58	2.77	13.05
HVAC Efficiency Improvement	Residential HVAC Early Retirement Tier 2	674	1.25	1.33	6,243	0.84	0.90	4.21	1.80	1.93	9.02
HVAC Efficiency Improvement	Residential HVAC Early Retirement Tier 3	41	1.67	1.57	7,132	0.07	0.06	0.29	0.14	0.12	0.58
HVAC Efficiency Improvement	Residential HVAC Efficiency Upgrade Tier 1	331	0.43	0.32	1,567	0.14	0.11	0.52	0.23	0.18	0.86
HVAC Efficiency Improvement	Residential HVAC Efficiency Upgrade Tier 2	137	0.47	0.40	1,891	0.06	0.05	0.26	0.14	0.12	0.59
HVAC Efficiency Improvement	Residential HVAC Efficiency Upgrade Tier 3	85	1.08	0.64	3,456	0.09	0.05	0.29	0.24	0.14	0.75
HVAC Efficiency Improvement	Residential Duct Repair	8,021	0.21	0.32	1,382	1.68	2.57	11.09	2.84	4.32	18.67
HVAC Efficiency Improvement	Residential ECM Fan	3	0.14	0.27	1,109	0.00	0.00	0.00	0.00	0.00	0.00
Heat Pump Water Heater	Residential HPWH	2,006	0.37	0.10	1,348	0.74	0.20	2.70	1.17	0.32	4.29
Ceiling Insulation	Residential Ceiling Insulation	509	0.80	0.10	575	0.41	0.05	0.29	1.35	0.17	0.97
High Performance Window	Residential Window Replacement	1,377	0.50	0.20	1,338	0.69	0.28	1.84	1.26	0.50	3.35
High Performance Window	Residential Window Film	160	0.00	0.20	788	0.00	0.03	0.13	0.00	0.06	0.32
Reflective Roof	Residential Reflective Roof	517	0.00	0.41	1,029	0.00	0.21	0.53	0.00	0.31	0.80
Variable Speed/Flow Pool Pump	Variable Speed/Flow Pool Pump	998	1.15	1.15	2,494	1.15	1.15	2.49	6.73	6.73	14.60
Energy Select	Energy Select	2,149	2.20	1.73	762	4.73	3.72	1.64	2.34	1.85	0.81
Energy Select Lite	Energy Select Lite	0	1.10	0.98	556	0.00	0.00	0.00	3.53	3.14	1.78
Self-Install Energy Efficiency	Residential Energy Star Refrigerator	2,753	0.03	0.04	271	0.08	0.11	0.75	0.17	0.22	1.52
Self-Install Energy Efficiency	Residential Energy Star Freezer	174	0.01	0.01	62	0.00	0.00	0.01	0.00	0.00	0.03
Self-Install Energy Efficiency	Residential Energy Star Window A/C	233	0.00	0.22	432	0.00	0.05	0.10	0.00	0.10	0.21
Self-Install Energy Efficiency	Residential Energy Star Clothes Washer	2,750	0.03	0.03	197	0.08	0.08	0.54	0.15	0.15	1.06
Self-Install Energy Efficiency	Residential CFL	0	0.00	0.00	55	0.00	0.00	0.00	0.27	0.19	4.45
Refrigerator Recycling	Residential Refrigerator Recycling	982	0.08	0.08	738	0.08	0.08	0.72	0.24	0.24	2.11
		Total Residential Applicable To Goa				17.83	17.23	63.92	33.80	32.91	124.64
Residential Energy Audit and Education	Residential Energy Audit	7,052	----	----	----	----	----	----	----	----	----
				Total Residential		17.83	17.23	63.92	33.80	32.91	124.64

Commercial and Industrial Programs	Measures	A Total Units	B Per Unit Win. kW	C Per Unit Sum. kW	D Per Unit kWh	E Total Win. MW	F Total Sum. MW	G Total GWh	H Cumulative Win. MW	I Cumulative Sum. MW	J Cumulative GWh
Commercial HVAC Retrocommissioning	Commercial HVAC Retrocommissioning	254	0.32	1.30	3,921	0.08	0.33	1.00	0.28	1.15	3.47
Commercial Building Efficiency	Commercial HVAC Program	2,731	0.00	0.15	652	0.00	0.41	1.78	0.00	0.66	2.89
Commercial Building Efficiency	Commercial Geothermal Heat Pump Program	128	0.27	0.29	685	0.03	0.04	0.09	0.11	0.12	0.29
Commercial Building Efficiency	Commercial HPWH Program	1	11.80	10.00	41,241	0.01	0.01	0.04	0.02	0.02	0.08
Commercial Building Efficiency	Commercial Ceiling/Roof Insulation Program	190,760	0.00	0.00	1	0.02	0.10	0.16	0.03	0.15	0.25
Commercial Building Efficiency	Commercial Window Film	9,805	0.00	0.00	11	0.00	0.03	0.11	0.00	0.10	0.35
Commercial Building Efficiency	Commercial Interior Lighting	849	1.00	1.00	4,380	0.85	0.85	3.72	2.01	2.01	8.80
Commercial Building Efficiency	Commercial Interior Lighting - LED	966	1.00	1.00	4,380	0.97	0.97	4.23	1.37	1.37	6.00
Commercial Building Efficiency	Commercial Occupancy Sensor - Interior Lighting	4,277	0.20	0.20	800	0.86	0.86	3.42	1.23	1.23	4.90
Commercial Building Efficiency	Commercial Reflective Roof	1,730,233	0.00	0.00	2	0.00	1.57	4.24	0.00	2.04	5.49
Occupancy Sensor HVAC Control	Commercial Occupancy Sensor - HVAC	4,825	0.00	0.03	512	0.00	0.13	2.47	0.00	0.14	2.73
High Efficiency Motor	Commercial EE Motor 1-5 HP	62	0.03	0.03	159	0.00	0.00	0.01	0.00	0.00	0.01
High Efficiency Motor	Commercial EE Motor 6-50 HP	371	0.02	0.02	94	0.01	0.01	0.03	0.02	0.02	0.07
High Efficiency Motor	Commercial EE Motor 51 + HP	0	0.01	0.01	36	0.00	0.00	0.00	0.01	0.01	0.06
Food Service Efficiency	Convection Oven	1	0.40	0.40	1,869	0.00	0.00	0.00	0.00	0.00	0.01
Food Service Efficiency	Fryer	9	0.20	0.20	1,160	0.00	0.00	0.01	0.00	0.00	0.03
Food Service Efficiency	Griddle	0	0.50	0.50	2,523	0.00	0.00	0.00	0.00	0.00	0.00
Food Service Efficiency	Steamer	4	13.79	13.79	60,081	0.06	0.06	0.24	0.06	0.06	0.24
Food Service Efficiency	Holding Cabinet	0	1.20	1.20	6,534	0.00	0.00	0.00	0.00	0.00	0.01
Food Service Efficiency	Ice Machine	6	0.20	0.20	1,797	0.00	0.00	0.01	0.00	0.00	0.04
Commercial/Industrial Custom Incentive	Commercial/Industrial Custom Incentive	4	----	----	----	0.15	0.34	1.97	0.74	1.16	7.08
Real Time Pricing	Real Time Pricing	0	1,000	2,000	----	0.00	0.00	----	4.00	8.00	----
		Total Commercial/Industrial Applicable to Goa				3.04	6.71	23.63	9.88	18.24	42.82
Commercial/Industrial Energy Analysis	Commercial/Industrial Energy Analysis	567	----	----	----	----	----	----	----	----	----
				Total Commercial/Industrial		3.04	6.71	23.63	9.88	18.24	42.82

Solar Programs	Measures	A Total Units	B Per Unit Win. kW	C Per Unit Sum. kW	D Per Unit kWh	E Total Win. MW	F Total Sum. MW	G Total GWh	H Cumulative Win. MW	I Cumulative Sum. MW	J Cumulative GWh
Residential Solar Thermal	Residential Solar Thermal	23	0.25	0.25	1,906	0.01	0.01	0.04	0.03	0.03	0.21
Residential Solar PV	Residential Solar PV	42	1.50	3.00	6,388	0.06	0.13	0.27	0.19	0.39	0.82
Commercial Solar PV	Commercial Solar PV	3	1.50	3.00	6,388	0.00	0.01	0.02	0.00	0.01	0.04
		Total Solar Programs				0.07	0.15	0.33	0.22	0.43	1.07

Column A: Actual achieved for the reporting year.
Column B: As filed in the Conservation Plan Filing
Column C: As filed in the Conservation Plan Filing
Column D: As filed in the Conservation Plan Filing
Column E: (Column A) X (Column B)
Column F: (Column A) X (Column C)
Column G: (Column A) X (Column D)
Column H: Annual Results plus any/all previous Annual Results for this conservation plan.
Column I: Annual Results plus any/all previous Annual Results for this conservation plan.
Column J: Annual Results plus any/all previous Annual Results for this conservation plan.

GULF POWER COMPANY

2013 DSM Progress Report

Savings at the Generator

2010 DSM PLAN

		A	B	C	D	E	F	G	H	I	J
Residential Programs	**Measures**	Total Units	Per Unit Win. kW	Per Unit Sum. kW	Per Unit kWh	Total Win. MW	Total Sum. MW	Total GWh	Cumulative Win. MW	Cumulative Sum. MW	Cumulative GWh
Residential Energy Audit and Education	Home Energy Reporting	39,171	0.08	0.08	327	3.13	3.13	12.81	3.13	3.13	12.81
Community Energy Saver	Residential Community Energy Saver	2,220	0.14	0.07	802	0.31	0.16	1.78	1.04	0.52	5.96
Landlord/Renter Custom Incentive	Landlord/Renter Customer Incentive Program	0	------	------	------	0.00	0.00	0.00	0.00	0.16	0.38
HVAC Efficiency Improvement	Residential HVAC Maintenance	11,344	0.34	0.41	1,424	3.86	4.65	16.15	7.12	8.58	29.79
HVAC Efficiency Improvement	Residential HVAC Early Retirement Tier 1	1,251	1.52	1.63	6,381	1.90	2.04	7.98	3.39	3.64	14.22
HVAC Efficiency Improvement	Residential HVAC Early Retirement Tier 2	674	1.64	1.75	6,805	1.11	1.18	4.59	2.38	2.53	9.84
HVAC Efficiency Improvement	Residential HVAC Early Retirement Tier 3	41	2.19	2.06	7,774	0.09	0.08	0.32	0.18	0.16	0.64
HVAC Efficiency Improvement	Residential HVAC Efficiency Upgrade Tier 1	331	0.56	0.42	1,708	0.19	0.14	0.57	0.31	0.23	0.94
HVAC Efficiency Improvement	Residential HVAC Efficiency Upgrade Tier 2	137	0.62	0.53	2,061	0.08	0.07	0.28	0.19	0.17	0.64
HVAC Efficiency Improvement	Residential HVAC Efficiency Upgrade Tier 3	85	1.42	0.84	3,767	0.12	0.07	0.32	0.30	0.18	0.82
HVAC Efficiency Improvement	Residential Duct Repair	8,021	0.28	0.42	1,506	2.25	3.37	12.08	3.79	5.67	20.35
HVAC Efficiency Improvement	Residential ECM Fan	3	0.18	0.35	1,209	0.00	0.00	0.00	0.00	0.00	0.00
Heat Pump Water Heater	Residential HPWH	2,006	0.49	0.13	1,469	0.98	0.26	2.95	1.56	0.41	4.68
Ceiling Insulation	Residential Ceiling Insulation	509	1.05	0.13	627	0.53	0.07	0.32	1.70	0.22	1.06
High Performance Window	Residential Window Replacement	1,377	0.66	0.26	1,458	0.91	0.36	2.01	1.65	0.65	3.66
High Performance Window	Residential Window Film	160	0.00	0.26	859	0.00	0.04	0.14	0.00	0.11	0.34
Reflective Roof	Residential Reflective Roof	517	0.00	0.54	1,122	0.00	0.28	0.58	0.00	0.42	0.87
Variable Speed/Flow Pool Pump	Variable Speed/Flow Pool Pump	998	1.51	1.51	2,718	1.51	1.51	2.71	8.84	8.84	15.90
Energy Select	Energy Select	2,149	2.89	2.27	831	6.21	4.88	1.78	3.08	2.41	0.88
Energy Select Lite	Energy Select Lite	0	1.44	1.29	606	0.00	0.00	0.00	4.63	4.13	1.94
Self-Install Energy Efficiency	Residential Energy Star Refrigerator	2,753	0.04	0.05	295	0.11	0.14	0.81	0.22	0.29	1.65
Self-Install Energy Efficiency	Residential Energy Star Freezer	174	0.01	0.01	89	0.00	0.00	0.02	0.00	0.00	0.04
Self-Install Energy Efficiency	Residential Energy Star Window A/C	233	0.00	0.29	471	0.00	0.07	0.11	0.00	0.14	0.23
Self-Install Energy Efficiency	Residential Energy Star Clothes Washer	2,750	0.04	0.04	215	0.10	0.10	0.59	0.20	0.20	1.15
Self-Install Energy Efficiency	Residential CFL	0	0.00	0.00	60	0.00	0.00	0.00	0.35	0.25	4.85
Refrigerator Recycling	Residential Refrigerator Recycling	982	0.11	0.11	804	0.10	0.10	0.79	0.30	0.30	2.31
	Total Residential Applicable To Goal					**23.49**	**22.70**	**69.69**	**44.42**	**43.34**	**136.96**
Residential Energy Audit and Education	Residential Energy Audit	7,952	------	------	------	------	------	------	------	------	------
	Total Residential					**23.49**	**22.70**	**69.69**	**44.42**	**43.34**	**136.96**
Commercial and Industrial Programs	**Measures**										
Commercial HVAC Retrocommissioning	Commercial HVAC Retrocommissioning	254	0.42	1.71	4,274	0.11	0.43	1.09	0.38	1.50	3.78
Commercial Building Efficiency	Commercial HVAC Program	2,731	0.00	0.20	711	0.00	0.55	1.94	0.00	0.89	3.14
Commercial Building Efficiency	Commercial Geothermal Heat Pump Program	128	0.35	0.38	747	0.04	0.05	0.10	0.14	0.16	0.32
Commercial Building Efficiency	Commercial HPWH Program	1	15.50	13.10	44,953	0.02	0.01	0.04	0.04	0.02	0.08
Commercial Building Efficiency	Commercial Ceiling/Roof Insulation Program	190,760	0.00	0.00	1	0.03	0.13	0.17	0.04	0.20	0.26
Commercial Building Efficiency	Commercial Window Film	9,805	0.00	0.00	12	0.00	0.04	0.12	0.00	0.13	0.38
Commercial Building Efficiency	Commercial Interior Lighting	849	1.31	1.31	4,774	1.11	1.11	4.05	2.63	2.63	9.58
Commercial Building Efficiency	Commercial Interior Lighting - LED	966	1.31	1.31	4,774	1.27	1.27	4.61	1.80	1.80	6.53
Commercial Building Efficiency	Commercial Occupancy Sensor - Interior Lighting	4,277	0.26	0.26	872	1.11	1.11	3.73	1.59	1.59	5.34
Commercial Building Efficiency	Commercial Reflective Roof	1,730,233	0.00	0.00	3	0.00	2.08	4.62	0.00	2.69	5.98
Occupancy Sensor HVAC Control	Commercial Occupancy Sensor - HVAC	4,825	0.00	0.03	558	0.00	0.16	2.69	0.00	0.18	2.97
High Efficiency Motor	Commercial EE Motor 1-5 HP	62	0.04	0.04	173	0.00	0.00	0.01	0.00	0.00	0.01
High Efficiency Motor	Commercial EE Motor 6-50 HP	371	0.02	0.02	102	0.01	0.01	0.04	0.02	0.02	0.08
High Efficiency Motor	Commercial EE Motor 51 + HP	0	0.01	0.01	39	0.00	0.00	0.00	0.01	0.01	0.08
Food Service Efficiency	Convection Oven	1	0.53	0.53	2,037	0.00	0.00	0.00	0.00	0.00	0.02
Food Service Efficiency	Fryer	9	0.26	0.26	1,264	0.00	0.00	0.01	0.00	0.00	0.03
Food Service Efficiency	Griddle	0	0.66	0.66	2,750	0.00	0.00	0.00	0.00	0.00	0.00
Food Service Efficiency	Steamer	4	18.11	18.11	65,488	0.07	0.07	0.26	0.07	0.07	0.26
Food Service Efficiency	Holding Cabinet	0	1.58	1.58	7,122	0.00	0.00	0.00	0.00	0.00	0.01
Food Service Efficiency	Ice Machine	6	0.26	0.26	1,959	0.00	0.00	0.01	0.00	0.00	0.04
Commercial/Industrial Custom Incentive	Commercial/Industrial Custom Incentive	4	------	------	------	0.19	0.44	2.14	0.97	1.51	8.59
Real Time Pricing	Real Time Pricing	0	1,313	2,627	------	0.00	0.00	------	5.25	10.51	------
	Total Commercial/Industrial Applicable to Goal					**3.96**	**7.46**	**25.63**	**12.94**	**23.91**	**47.48**
Commercial/Industrial Energy Analysis	Commercial/Industrial Energy Analysis	567	------	------	------	------	------	------	------	------	------
	Total Commercial/Industrial					**3.96**	**7.46**	**25.63**	**12.94**	**23.91**	**47.48**
Solar Programs	**Measures**										
Residential Solar Thermal	Residential Solar Thermal	23	0.33	0.33	2,078	0.01	0.01	0.05	0.04	0.04	0.23
Residential Solar PV	Residential Solar PV	42	1.97	3.94	6,963	0.08	0.17	0.29	0.25	0.51	0.89
Commercial Solar PV	Commercial Solar PV	3	1.97	3.94	6,963	0.01	0.01	0.02	0.01	0.01	0.04
	Total Solar Programs					**0.10**	**0.19**	**0.36**	**0.30**	**0.56**	**1.16**

Column A:	Actual achieved for the reporting year
Column B:	As filed in the Conservation Plan Filing
Column C:	As filed in the Conservation Plan Filing
Column D:	As filed in the Conservation Plan Filing
Column E:	(Column A) X (Column B)
Column F:	(Column A) X (Column C)
Column G:	(Column A) X (Column D)
Column H:	Annual Results plus any/all previous Annual Results for this conservation plan
Column I:	Annual Results plus any/all previous Annual Results for this conservation plan
Column J:	Annual Results plus any/all previous Annual Results for this conservation plan

Comparison of Achieved kW and kWh Reductions

With Public Service Commission Established Goals

at the Generator

2010 DSM PLAN

Utility: GULF POWER COMPANY

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
	Total Achieved	Com. Appr. Goal	% Variance	Total Achieved	Com. Appr. Goal	% Variance	Total Achieved	Com. Appr. Goal	% Variance
2010	...	5.9	-100%	...	7.5	-100%	...	35.0	-100%
2011	7.04	6.5	8%	7.24	8.3	-13%	28.30	37.6	-25%
2012	19.49	7.4	163%	19.29	9.4	105%	63.66	40.6	57%
2013	23.49	8.5	176%	22.70	10.5	116%	69.69	43.8	59%
2014		9.5			11.7			46.8	
2015		10.9			12.8			50.2	
2016		12.1			14.0			53.6	
2017		12.7			14.7			55.4	
2018		13.3			14.9			56.2	
2019		13.7			15.1			56.7	

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
	Total Achieved	Com. Appr. Goal	% Variance	Total Achieved	Com. Appr. Goal	% Variance	Total Achieved	Com. Appr. Goal	% Variance
2010	...	0.5	-100%	...	1.2	-100%	...	3.2	-100%
2011	2.89	0.6	382%	5.13	1.6	221%	11.67	5.6	108%
2012	7.63	0.8	854%	14.54	2.1	592%	12.59	7.7	64%
2013	3.96	0.9	340%	7.46	2.4	211%	25.63	9.5	170%
2014		1.0			2.7			10.8	
2015		1.0			2.9			11.7	
2016		1.2			3.0			12.3	
2017		1.1			3.2			12.7	
2018		1.1			3.1			12.5	
2019		1.1			3.1			11.9	

Total Company (including Solar)

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
	Total Achieved	Com. Appr. Goal	% Variance	Total Achieved	Com. Appr. Goal	% Variance	Total Achieved	Com. Appr. Goal	% Variance
2010	...	6.4	-100%	...	8.7	-100%	...	38.2	-100%
2011	10.03	7.1	41%	12.55	9.9	27%	40.37	43.2	-7%
2012	27.23	8.2	232%	34.02	11.5	196%	76.65	48.3	59%
2013	27.55	9.4	193%	30.35	12.9	135%	95.68	53.3	80%
2014		10.5			14.4			57.6	
2015		11.9			15.7			61.9	
2016		13.3			17.0			65.9	
2017		13.8			17.9			68.1	
2018		14.4			18.0			68.7	
2019		14.8			18.2			68.6	

Robert L. McGee, Jr.
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GULF POWER
A SOUTHERN COMPANY

March 1, 2016

Mr. Gregory Shafer, Director
Division of Economics
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee FL 32399-0868

Dear Mr. Shafer:

Attached is Gulf Power Company's 2015 Annual FEECA Program Progress Report.

Sincerely,

Robert L. McGee, Jr.
Regulatory and Pricing Manager

md

Attachment

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Energy Audit and Education

Measure Name: Residential Energy Audit

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G - Column D)
2010	374,936	373,219	7,860	2.11%	...	...	...	...
2011	377,336	375,619	16,080	4.28%	10,029	10,029	2.67%	(6,051)
2012	381,544	379,827	24,842	6.54%	8,863	18,892	4.97%	(5,950)
2013	388,378	386,661	34,392	8.89%	7,952	26,844	6.94%	(7,548)
2014	396,913	395,196	44,453	11.25%	7,927	34,771	8.80%	(9,682)
2015	405,062	403,345	54,398	13.49%	5,137	39,908	9.89%	(14,490)

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	------	------	------	------
Summer kW Reduction	------	------	------	------
Annual kWh Reduction	------	------	------	------

	Annual
Utility Cost per Installation:	$232
Total Program Cost of the Utility ($000):	$1,190
Net Benefits of Measures Installed During Reporting Period:	N/A

Note: The demand and energy savings of this program are not applied toward the established DSM goals.

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Energy Audit and Education

Measure Name: Home Energy Reporting

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G - Column D)
2010	374,936	373,219	35,000	9.38%	...	...	...	...
2011	377,336	375,619	35,000	9.32%	39,797	39,797	10.60%	4,797
2012	381,544	379,827	35,000	9.21%	39,213	39,213	10.32%	4,213
2013	388,378	386,661	35,000	9.05%	39,171	39,171	10.13%	4,171
2014	396,913	395,196	0	0.00%	39,171	39,171	9.91%	39,171
2015	405,062	403,345	0	0.00%	0	39,171	9.71%	39,171

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.06	0.08	2,350	3,134
Summer kW Reduction	0.06	0.08	2,350	3,134
Annual kWh Reduction	300	327	11,751,300	12,808,917

	Annual
Utility Cost per Installation:	N/A
Total Program Cost of the Utility ($000):	$40
Net Benefits of Measures Installed During Reporting Period:	($177,363)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Community Energy Saver

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2010	374,936	130,627	1,250	0.96%	...	...	...	...
2011	377,336	131,467	3,750	2.85%	1,881	1,881	1.43%	(1,869)
2012	381,544	132,939	6,250	4.70%	3,327	5,208	3.92%	(1,042)
2013	388,378	135,331	8,750	6.47%	2,220	7,428	5.49%	(1,322)
2014	396,913	138,319	11,250	8.13%	2,326	9,754	7.05%	(1,496)
2015	405,062	141,171	12,750	9.03%	1,737	11,491	8.14%	(1,259)

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.11	0.14	191	243
Summer kW Reduction	0.05	0.07	87	122
Annual kWh Reduction	736	802	1,278,432	1,393,074

	Annual
Utility Cost per Installation:	$327
Total Program Cost of the Utility ($000):	$567
Net Benefits of Measures Installed During Reporting Period:	($157,908)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Landlord-Renter Custom Incentive

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	750	0.20%	...	...	...	...
2011	377,336	375,619	1,500	0.40%	1	1	0.00%	(1,499)
2012	381,544	379,827	2,250	0.59%	0	1	0.00%	(2,249)
2013	388,378	386,661	3,000	0.78%	0	1	0.00%	(2,999)
2014	396,913	395,196	3,750	0.95%	0	1	0.00%	(3,749)
2015	405,062	403,345	4,500	1.12%	0	1	0.00%	(4,499)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	------	------	0	0
Summer kW Reduction	------	------	0	0
Annual kWh Reduction	------	------	0	0

	Annual	
Utility Cost per Installation:	N/A	
Total Program Cost of the Utility ($000):	$41	
Net Benefits of Measures Installed During Reporting Period:	N/A	No incentives paid

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Landlord/Renter Custom Incentive Program

Program Start Date: June, 2011

Reporting Period: Annual 2015 0

	Meter			Generator		
	Summer kW	**Winter kW**	**Energy kWh**	**Summer kW**	**Winter kW**	**Energy kWh**
2010	...	...	...	...	...	...
2011	121	0	286,242	159	0	375,922
2012	0	0	0	0	0	0
2013	0	0	0	0	0	0
2014						
Cumulative	121	0	286,242	159	0	375,922

Projects - 2013	Meter			Generator		
	Summer kW	**Winter kW**	**Energy kWh**	**Summer kW**	**Winter kW**	**Energy kWh**
Total	0.00	0.00	0	0.00	0.00	0

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential HVAC Efficiency Improvement Program

Measure Name: Residential HVAC Maintenance

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	1,280	0.34%	...	...	...	...
2011	377,336	375,619	3,680	0.98%	2,789	2,789	0.74%	(891)
2012	381,544	379,827	7,760	2.04%	6,793	9,582	2.52%	1,822
2013	388,378	386,661	14,260	3.69%	11,344	20,926	5.41%	6,666
2014	396,913	395,196	24,260	6.14%	5,134	26,060	6.59%	1,800
2015	405,062	403,345	33,260	8.25%	5,708	31,768	7.88%	(1,492)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.26	0.34	1,484	1,941
Summer kW Reduction	0.31	0.41	1,769	2,340
Annual kWh Reduction	1,306	1,424	7,454,648	8,128,192

	Annual
Utility Cost per Installation:	$177
Total Program Cost of the Utility ($000):	$1,011
Net Benefits of Measures Installed During Reporting Period:	($529,309)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential HVAC Efficiency Improvement Program

Measure Name: Residential HVAC Early Retirement Tier 1

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	340	0.09%	...	...	...	...
2011	377,336	375,619	978	0.26%	176	176	0.05%	(802)
2012	381,544	379,827	2,062	0.54%	803	979	0.26%	(1,083)
2013	388,378	386,661	3,796	0.98%	1,251	2,230	0.58%	(1,566)
2014	396,913	395,196	6,461	1.63%	1,015	3,245	0.82%	(3,216)
2015	405,062	403,345	9,086	2.25%	1,099	4,344	1.08%	(4,742)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	1.16	1.52	1,275	1,670
Summer kW Reduction	1.24	1.63	1,363	1,791
Annual kWh Reduction	5,854	6,381	6,433,546	7,012,719

	Annual
Utility Cost per Installation:	$50
Total Program Cost of the Utility ($000):	$55
Net Benefits of Measures Installed During Reporting Period:	($333,428)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential HVAC Efficiency Improvement Program

Measure Name: Residential HVAC Early Retirement Tier 2

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	50	0.01%	...	...	...	...
2011	377,336	375,619	140	0.04%	225	225	0.06%	85
2012	381,544	379,827	293	0.08%	547	772	0.20%	479
2013	388,378	386,661	538	0.14%	674	1,446	0.37%	908
2014	396,913	395,196	913	0.23%	739	2,185	0.55%	1,272
2015	405,062	403,345	1,288	0.32%	770	2,955	0.73%	1,667

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	1.25	1.64	963	1,263
Summer kW Reduction	1.33	1.75	1,024	1,348
Annual kWh Reduction	6,243	6,805	4,807,110	5,239,850

	Annual
Utility Cost per Installation:	$61
Total Program Cost of the Utility ($000):	$47
Net Benefits of Measures Installed During Reporting Period:	($270,279)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential HVAC Efficiency Improvement Program

Measure Name: Residential HVAC Early Retirement Tier 3

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	10	0.00%	...	...	...	...
2011	377,336	375,619	30	0.01%	0	0	0.00%	(30)
2012	381,544	379,827	60	0.02%	41	41	0.01%	(19)
2013	388,378	386,661	110	0.03%	41	82	0.02%	(28)
2014	396,913	395,196	185	0.05%	45	127	0.03%	(58)
2015	405,062	403,345	260	0.06%	39	166	0.04%	(94)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	1.67	2.19	65	85
Summer kW Reduction	1.57	2.06	61	80
Annual kWh Reduction	7,132	7,774	278,148	303,186

	Annual
Utility Cost per Installation:	$3,208
Total Program Cost of the Utility ($000):	$125
Net Benefits of Measures Installed During Reporting Period:	($26,111)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential HVAC Efficiency Improvement Program

Measure Name: Residential HVAC Efficiency Upgrade Tier 1

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	272	0.07%	...	...	...	...
2011	377,336	375,619	782	0.21%	30	30	0.01%	(752)
2012	381,544	379,827	1,649	0.43%	187	217	0.06%	(1,432)
2013	388,378	386,661	3,037	0.79%	331	548	0.14%	(2,489)
2014	396,913	395,196	5,169	1.31%	261	809	0.20%	(4,360)
2015	405,062	403,345	7,044	1.75%	249	1,058	0.26%	(5,986)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.43	0.56	107	139
Summer kW Reduction	0.32	0.42	80	105
Annual kWh Reduction	1,567	1,708	390,183	425,292

	Annual
Utility Cost per Installation:	$2,507
Total Program Cost of the Utility ($000):	$624
Net Benefits of Measures Installed During Reporting Period:	($77,876)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential HVAC Efficiency Improvement Program

Measure Name: Residential HVAC Efficiency Upgrade Tier 2

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	38	0.01%	...	...	...	...
2011	377,336	375,619	110	0.03%	50	50	0.01%	(60)
2012	381,544	379,827	232	0.06%	127	177	0.05%	(55)
2013	388,378	386,661	428	0.11%	137	314	0.08%	(114)
2014	396,913	395,196	728	0.18%	225	539	0.14%	(189)
2015	405,062	403,345	1,028	0.25%	120	659	0.16%	(369)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.47	0.62	56	74
Summer kW Reduction	0.40	0.53	48	64
Annual kWh Reduction	1,891	2,061	226,920	247,320

	Annual
Utility Cost per Installation:	$5,704
Total Program Cost of the Utility ($000):	$684
Net Benefits of Measures Installed During Reporting Period:	($81,832)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential HVAC Efficiency Improvement Program

Measure Name: Residential HVAC Efficiency Upgrade Tier 3

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	10	0.00%	...	...	...	...
2011	377,336	375,619	28	0.01%	45	45	0.01%	17
2012	381,544	379,827	59	0.02%	88	133	0.04%	74
2013	388,378	386,661	108	0.03%	85	218	0.06%	110
2014	396,913	395,196	183	0.05%	100	318	0.08%	135
2015	405,062	403,345	258	0.06%	73	391	0.10%	133

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	1.08	1.42	79	104
Summer kW Reduction	0.64	0.84	47	61
Annual kWh Reduction	3,456	3,767	252,288	274,991

	Annual
Utility Cost per Installation:	$648
Total Program Cost of the Utility ($000):	$47
Net Benefits of Measures Installed During Reporting Period:	($24,251)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential HVAC Efficiency Improvement Program

Measure Name: Residential Duct Repair

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	0	0.00%	...	...	...	...
2011	377,336	375,619	1,000	0.27%	170	170	0.05%	(830)
2012	381,544	379,827	3,000	0.79%	5,320	5,490	1.45%	2,490
2013	388,378	386,661	7,200	1.86%	8,021	13,511	3.49%	6,311
2014	396,913	395,196	13,700	3.47%	2,647	16,158	4.09%	2,458
2015	405,062	403,345	19,700	4.88%	3,965	20,123	4.99%	423

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.21	0.28	833	1,110
Summer kW Reduction	0.32	0.42	1,269	1,665
Annual kWh Reduction	1,382	1,506	5,479,630	5,971,290

	Annual
Utility Cost per Installation:	$329
Total Program Cost of the Utility ($000):	$1,305
Net Benefits of Measures Installed During Reporting Period:	($397,096)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential HVAC Efficiency Improvement Program

Measure Name: Residential ECM Fan

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2010	374,936	373,219	0	0.00%	...	...	...	...
2011	377,336	375,619	400	0.11%	0	0	0.00%	(400)
2012	381,544	379,827	1,150	0.30%	3	3	0.00%	(1,147)
2013	388,378	386,661	2,425	0.63%	3	6	0.00%	(2,419)
2014	396,913	395,196	4,425	1.12%	0	6	0.00%	(4,419)
2015	405,062	403,345	7,425	1.84%	0	6	0.00%	(7,419)

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.14	0.18	0.00	0.00
Summer kW Reduction	0.27	0.35	0.00	0.00
Annual kWh Reduction	1,109	1,209	0	0

	Annual	
Utility Cost per Installation:	N/A	
Total Program Cost of the Utility ($000):	$0	
Net Benefits of Measures Installed During Reporting Period:	N/A	No Program Participants

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Heat Pump Water Heater

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	100	0.03%	...	...	...	...
2011	377,336	375,619	400	0.11%	304	304	0.08%	(96)
2012	381,544	379,827	1,000	0.26%	873	1,177	0.31%	177
2013	388,378	386,661	1,800	0.47%	2,006	3,183	0.82%	1,383
2014	396,913	395,196	2,800	0.71%	471	3,654	0.92%	854
2015	405,062	403,345	4,000	0.99%	298	3,952	0.98%	(48)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.37	0.49	110	146
Summer kW Reduction	0.10	0.13	30	39
Annual kWh Reduction	1,348	1,469	401,704	437,762

	Annual
Utility Cost per Installation:	$424
Total Program Cost of the Utility ($000):	$126
Net Benefits of Measures Installed During Reporting Period:	($61,465)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Ceiling Insulation Program

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	100	0.03%	...	...	...	...
2011	377,336	375,619	300	0.08%	394	394	0.10%	94
2012	381,544	379,827	650	0.17%	780	1,174	0.31%	524
2013	388,378	386,661	1,150	0.30%	509	1,683	0.44%	533
2014	396,913	395,196	1,650	0.42%	271	1,954	0.49%	304
2015	405,062	403,345	2,150	0.53%	338	2,292	0.57%	142

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.80	1.05	270	355
Summer kW Reduction	0.10	0.13	34	44
Annual kWh Reduction	575	627	194,350	211,926

	Annual
Utility Cost per Installation:	$329
Total Program Cost of the Utility ($000):	$111
Net Benefits of Measures Installed During Reporting Period:	($27,164)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential High Performance Window Program

Measure Name: Residential Window Replacement

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	100	0.03%	...	...	...	...
2011	377,336	375,619	300	0.08%	471	471	0.13%	171
2012	381,544	379,827	650	0.17%	658	1,129	0.30%	479
2013	388,378	386,661	1,150	0.30%	1,377	2,506	0.65%	1,356
2014	396,913	395,196	1,900	0.48%	626	3,132	0.79%	1,232
2015	405,062	403,345	2,900	0.72%	511	3,643	0.90%	743

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.50	0.66	256	337
Summer kW Reduction	0.20	0.26	102	133
Annual kWh Reduction	1,338	1,458	683,718	745,038

	Annual
Utility Cost per Installation:	$76
Total Program Cost of the Utility ($000):	$39
Net Benefits of Measures Installed During Reporting Period:	($47,012)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential High Performance Window Program

Measure Name: Residential Window Film

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	50	0.01%	...	...	...	...
2011	377,336	375,619	150	0.04%	64	64	0.02%	(86)
2012	381,544	379,827	350	0.09%	178	242	0.06%	(108)
2013	388,378	386,661	550	0.14%	160	402	0.10%	(148)
2014	396,913	395,196	750	0.19%	56	458	0.12%	(292)
2015	405,062	403,345	950	0.24%	96	554	0.14%	(396)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.00	0.00	0	0
Summer kW Reduction	0.20	0.26	19	25
Annual kWh Reduction	788	859	75,648	82,464

	Annual
Utility Cost per Installation:	$63
Total Program Cost of the Utility ($000):	$6
Net Benefits of Measures Installed During Reporting Period:	($5,854)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Reflective Roof

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	100	0.03%	...	...	...	...
2011	377,336	375,619	300	0.08%	30	30	0.01%	(270)
2012	381,544	379,827	600	0.16%	229	259	0.07%	(341)
2013	388,378	386,661	1,000	0.26%	517	776	0.20%	(224)
2014	396,913	395,196	1,500	0.38%	97	873	0.22%	(627)
2015	405,062	403,345	2,100	0.52%	155	1,028	0.25%	(1,072)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.00	0.00	0	0
Summer kW Reduction	0.41	0.54	64	84
Annual kWh Reduction	1,029	1,122	159,495	173,910

	Annual
Utility Cost per Installation:	$744
Total Program Cost of the Utility ($000):	$115
Net Benefits of Measures Installed During Reporting Period:	($17,550)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Variable Speed/Flow Pool Pump

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	100	0.03%	...	...	...	...
2011	377,336	375,619	250	0.07%	1,363	1,363	0.36%	1,113
2012	381,544	379,827	500	0.13%	3,491	4,854	1.28%	4,354
2013	388,378	386,661	850	0.22%	998	5,852	1.51%	5,002
2014	396,913	395,196	1,250	0.32%	287	6,139	1.55%	4,889
2015	405,062	403,345	1,650	0.41%	223	6,362	1.58%	4,712

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	1.15	1.51	256	337
Summer kW Reduction	1.15	1.51	256	337
Annual kWh Reduction	2,494	2,718	556,162	606,114

	Annual
Utility Cost per Installation:	$385
Total Program Cost of the Utility ($000):	$86
Net Benefits of Measures Installed During Reporting Period:	($22,020)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Energy Select (formerly GoodCents Select)

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	1,000	0.27%	...	...	...	...
2011	377,336	375,619	2,000	0.53%	(667)	(667)	-0.18%	(2,667)
2012	381,544	379,827	3,000	0.79%	(416)	(1,083)	-0.29%	(4,083)
2013	388,378	386,661	4,000	1.03%	2,149	1,066	0.28%	(2,934)
2014	396,913	395,196	5,000	1.27%	1,754	2,820	0.71%	(2,180)
2015	405,062	403,345	6,000	1.49%	1,394	4,214	1.04%	(1,786)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	2.20	2.89	3,067	4,028
Summer kW Reduction	1.73	2.27	2,412	3,167
Annual kWh Reduction	762	831	1,062,228	1,157,829

	Annual
Utility Cost per Installation:	$1,062
Total Program Cost of the Utility ($000):	$2,283
Net Benefits of Measures Installed During Reporting Period:	($1,373,108)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Energy Select Lite

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	300	0.08%	...	...	...	...
2011	377,336	375,619	900	0.24%	992	992	0.26%	92
2012	381,544	379,827	1,500	0.39%	2,215	3,207	0.84%	1,707
2013	388,378	386,661	2,100	0.54%	0	3,207	0.83%	1,107
2014	396,913	395,196	2,700	0.68%	0	3,207	0.81%	507
2015	405,062	403,345	3,300	0.82%	0	3,207	0.80%	(93)

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	1.10	1.44	0	0
Summer kW Reduction	0.98	1.29	0	0
Annual kWh Reduction	556	606	0	0

	Annual	
Utility Cost per Installation:	N/A	
Total Program Cost of the Utility ($000):	$0	
Net Benefits of Measures Installed During Reporting Period:	N/A	Combined with Energy Select for current reporting

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Self-Install Energy Efficiency

Measure Name: Residential Energy Star Refrigerator

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	1,000	0.27%	...	...	...	...
2011	377,336	375,619	3,000	0.80%	502	502	0.13%	(2,498)
2012	381,544	379,827	5,000	1.32%	2,327	2,829	0.74%	(2,171)
2013	388,378	386,661	7,500	1.94%	2,753	5,582	1.44%	(1,918)
2014	396,913	395,196	10,500	2.66%	293	5,875	1.49%	(4,625)
2015	405,062	403,345	14,000	3.47%	657	6,532	1.62%	(7,468)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.03	0.04	20	26
Summer kW Reduction	0.04	0.05	26	33
Annual kWh Reduction	271	295	178,047	193,815

	Annual
Utility Cost per Installation:	$76
Total Program Cost of the Utility ($000):	$50
Net Benefits of Measures Installed During Reporting Period:	($16,132)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Self-Install Energy Efficiency

Measure Name: Residential Energy Star Freezer

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2010	374,936	373,219	200	0.05%	...	...	...	...
2011	377,336	375,619	600	0.16%	36	36	0.01%	(564)
2012	381,544	379,827	1,100	0.29%	199	235	0.06%	(865)
2013	388,378	386,661	1,800	0.47%	174	409	0.11%	(1,391)
2014	396,913	395,196	2,500	0.63%	16	425	0.11%	(2,075)
2015	405,062	403,345	3,200	0.79%	37	462	0.11%	(2,738)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.010	0.013	0	0
Summer kW Reduction	0.011	0.014	0	1
Annual kWh Reduction	82	89	3,034	3,293

	Annual
Utility Cost per Installation:	$76
Total Program Cost of the Utility ($000):	$3
Net Benefits of Measures Installed During Reporting Period:	($500)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Self-Install Energy Efficiency

Measure Name: Residential Energy Star Window A/C

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2010	374,936	373,219	150	0.04%	...	...	...	...
2011	377,336	375,619	450	0.12%	36	36	0.01%	(414)
2012	381,544	379,827	850	0.22%	204	240	0.06%	(610)
2013	388,378	386,661	1,300	0.34%	233	473	0.12%	(827)
2014	396,913	395,196	1,800	0.46%	38	511	0.13%	(1,289)
2015	405,062	403,345	2,200	0.55%	234	745	0.18%	(1,455)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.00	0.00	0	0
Summer kW Reduction	0.22	0.29	51	68
Annual kWh Reduction	432	471	101,088	110,214

	Annual
Utility Cost per Installation:	$76
Total Program Cost of the Utility ($000):	$18
Net Benefits of Measures Installed During Reporting Period:	($4,921)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Self-Install Energy Efficiency

Measure Name: Residential Energy Star Clothes Washer

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	500	0.13%	...	...	...	...
2011	377,336	375,619	2,000	0.53%	417	417	0.11%	(1,583)
2012	381,544	379,827	4,500	1.18%	2,198	2,615	0.69%	(1,885)
2013	388,378	386,661	8,000	2.07%	2,750	5,365	1.39%	(2,635)
2014	396,913	395,196	12,500	3.16%	330	5,695	1.44%	(6,805)
2015	405,062	403,345	18,000	4.46%	685	6,380	1.58%	(11,620)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.028	0.037	19	25
Summer kW Reduction	0.028	0.037	19	25
Annual kWh Reduction	197	215	134,945	147,275

	Annual
Utility Cost per Installation:	$76
Total Program Cost of the Utility ($000):	$52
Net Benefits of Measures Installed During Reporting Period:	($17,265)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Self-Install Energy Efficiency

Measure Name: Residential CFL

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	250,000	66.98%	...	...	...	...
2011	377,336	375,619	400,000	106.49%	3,200	3,200	0.85%	(396,800)
2012	381,544	379,827	600,000	157.97%	77,646	80,846	21.28%	(519,154)
2013	388,378	386,661	600,000	155.17%	0	80,846	20.91%	(519,154)
2014	396,913	395,196	600,000	151.82%	0	80,846	20.46%	(519,154)
2015	405,062	403,345	600,000	148.76%	0	80,846	20.04%	(519,154)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.00333	0.00437	0	0
Summer kW Reduction	0.00237	0.00311	0	0
Annual kWh Reduction	55	60	0	0

	Annual	
Utility Cost per Installation:	N/A	
Total Program Cost of the Utility ($000):	$0	
Net Benefits of Measures Installed During Reporting Period:	N/A	No Program Participants

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Refrigerator Recycling

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2010	374,936	373,219	0	0.00%	...	...	...	...
2011	377,336	375,619	1,750	0.47%	815	815	0.22%	(935)
2012	381,544	379,827	5,250	1.38%	1,064	1,879	0.49%	(3,371)
2013	388,378	386,661	8,750	2.26%	982	2,861	0.74%	(5,889)
2014	396,913	395,196	12,250	3.10%	903	3,764	0.95%	(8,486)
2015	405,062	403,345	15,750	3.90%	0	3,764	0.93%	(11,986)

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.08	0.11	0	0
Summer kW Reduction	0.08	0.11	0	0
Annual kWh Reduction	738	804	0	0

	Annual	
Utility Cost per Installation:	N/A	
Total Program Cost of the Utility ($000):	$8	
Net Benefits of Measures Installed During Reporting Period:	N/A	No Program Participants

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial/Industrial Audit

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	54,648	46,618	600	1.29%	...	...	...	...
2011	55,016	46,872	1,200	2.56%	476	476	1.02%	(724)
2012	55,584	47,317	1,800	3.80%	420	896	1.89%	(904)
2013	56,431	48,039	2,400	5.00%	567	1,463	3.05%	(937)
2014	57,460	48,940	3,000	6.13%	487	1,950	3.98%	(1,050)
2015	58,450	49,802	3,600	7.23%	327	2,277	4.57%	(1,323)

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	------	------	------	------
Summer kW Reduction	------	------	------	------
Annual kWh Reduction	------	------	------	------

	Annual
Utility Cost per Installation:	$1,276
Total Program Cost of the Utility ($000):	$417
Net Benefits of Measures Installed During Reporting Period:	N/A

Note: The demand and energy savings of this program are not applied toward the established DSM goals.

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial HVAC Retrocommissioning

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	54,648	46,618	145	0.31%	...	...	...	...
2011	55,016	46,872	545	1.16%	323	323	0.69%	(222)
2012	55,584	47,317	1,195	2.53%	307	630	1.33%	(565)
2013	56,431	48,039	1,995	4.15%	254	884	1.84%	(1,111)
2014	57,460	48,940	2,995	6.12%	64	948	1.94%	(2,047)
2015	58,450	49,802	4,195	8.42%	17	965	1.94%	(3,230)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.32	0.42	5	7
Summer kW Reduction	1.30	1.71	22	29
Annual kWh Reduction	3,921	4,274	66,657	72,658

	Annual
Utility Cost per Installation:	$1,221
Total Program Cost of the Utility ($000):	$21
Net Benefits of Measures Installed During Reporting Period:	($4,111)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Building Efficiency Program

Measure Name: Commercial HVAC Program

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2010	54,648	46,618	150	N/A	...	...	N/A	...
2011	55,016	46,872	450	N/A	85	85	N/A	(365)
2012	55,584	47,317	800	N/A	1,608	1,693	N/A	893
2013	56,431	48,039	1,200	N/A	2,731	4,424	N/A	3,224
2014	57,460	48,940	1,700	N/A	1,606	6,030	N/A	4,330
2015	58,450	49,802	2,300	N/A	1,296	7,326	N/A	5,026

*Tons of HVAC installed

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.00	0.00	0	0
Summer kW Reduction	0.15	0.20	194	259
Annual kWh Reduction	652	711	844,992	921,456

	Annual
Utility Cost per Installation:	$76
Total Program Cost of the Utility ($000):	$98
Net Benefits of Measures Installed During Reporting Period:	($46,398)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Building Efficiency Program

Measure Name: Commercial Geothermal Heat Pump Program

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2010	54,648	46,618	150	N/A	...	...	N/A	...
2011	55,016	46,872	325	N/A	0	0	N/A	(325)
2012	55,584	47,317	525	N/A	290	290	N/A	(235)
2013	56,431	48,039	775	N/A	128	418	N/A	(357)
2014	57,460	48,940	1,025	N/A	73	491	N/A	(534)
2015	58,450	49,802	1,275	N/A	0	491	N/A	(784)

*Tons of Geothermal HVAC installed

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.27	0.35	0	0
Summer kW Reduction	0.29	0.38	0	0
Annual kWh Reduction	685	747	0	0

	Annual	
Utility Cost per Installation:	N/A	
Total Program Cost of the Utility ($000):	$0	
Net Benefits of Measures Installed During Reporting Period:	N/A	No Program Participants

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Building Efficiency Program

Measure Name: Commercial HPWH Program

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2010	54,648	46,618	1	N/A	...	...	N/A	...
2011	55,016	46,872	2	N/A	0	0	N/A	(2)
2012	55,584	47,317	3	N/A	1	1	N/A	(2)
2013	56,431	48,039	4	N/A	1	2	N/A	(2)
2014	57,460	48,940	5	N/A	1	3	N/A	(2)
2015	58,450	49,802	7	N/A	0	3	N/A	(4)

*Installations (5 tons)

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	11.80	15.5	0	0
Summer kW Reduction	10.00	13.1	0	0
Annual kWh Reduction	41,241	44,953	0	0

	Annual	
Utility Cost per Installation:	N/A	
Total Program Cost of the Utility ($000):	$0	
Net Benefits of Measures Installed During Reporting Period:	N/A	No Program Participants

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Building Efficiency Program

Measure Name: Commercial Ceiling/Roof Insulation Program

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2010	54,648	46,618	29,965	N/A	...	...	N/A	...
2011	55,016	46,872	85,095	N/A	22,180	22,180	N/A	(62,915)
2012	55,584	47,317	165,596	N/A	80,704	102,884	N/A	(62,712)
2013	56,431	48,039	267,555	N/A	190,760	293,644	N/A	26,089
2014	57,460	48,940	387,349	N/A	4,742	298,386	N/A	(88,963)
2015	58,450	49,802	521,669	N/A	8,511	306,897	N/A	(214,772)

*Square feet of insulation installed

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.00011	0.00014	1	1
Summer kW Reduction	0.00052	0.00068	4	6
Annual kWh Reduction	0.863	0.90	7,345	7,660

	Annual
Utility Cost per Installation:	$0
Total Program Cost of the Utility ($000):	$1
Net Benefits of Measures Installed During Reporting Period:	($139)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Building Efficiency Program

Measure Name: Commercial Window Film

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2010	54,648	46,618	8,620	N/A	...	...	N/A	...
2011	55,016	46,872	24,973	N/A	0	0	N/A	(24,973)
2012	55,584	47,317	49,250	N/A	21,863	21,863	N/A	(27,387)
2013	56,431	48,039	80,015	N/A	9,805	31,668	N/A	(48,347)
2014	57,460	48,940	115,900	N/A	2,122	33,790	N/A	(82,110)
2015	58,450	49,802	155,652	N/A	2,503	36,293	N/A	(119,359)

*Square feet of window film installed

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.00	0.00	0	0
Summer kW Reduction	0.0033	0.0043	7	9
Annual kWh Reduction	11	12	23,342	25,464

	Annual
Utility Cost per Installation:	$1
Total Program Cost of the Utility ($000):	$2
Net Benefits of Measures Installed During Reporting Period:	($1,125)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Building Efficiency Program

Measure Name: Commercial Interior Lighting

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2010	54,648	46,618	50	N/A	...	...	N/A	...
2011	55,016	46,872	125	N/A	282	282	N/A	157
2012	55,584	47,317	225	N/A	876	1,158	N/A	933
2013	56,431	48,039	375	N/A	849	2,007	N/A	1,632
2014	57,460	48,940	525	N/A	355	2,362	N/A	1,837
2015	58,450	49,802	650	N/A	164	2,526	N/A	1,876

*kW of lighting reduction

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	1.00	1.31	164	215
Summer kW Reduction	1.00	1.31	164	215
Annual kWh Reduction	4,380	4,774	718,320	782,936

	Annual
Utility Cost per Installation:	$108
Total Program Cost of the Utility ($000):	$0
Net Benefits of Measures Installed During Reporting Period:	($17,810)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Building Efficiency Program

Measure Name: Commercial Interior Lighting - LED

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2010	54,648	46,618	20	N/A	...	...	N/A	...
2011	55,016	46,872	50	N/A	61	61	N/A	11
2012	55,584	47,317	90	N/A	342	403	N/A	313
2013	56,431	48,039	140	N/A	966	1,369	N/A	1,229
2014	57,460	48,940	200	N/A	1,317	2,686	N/A	2,486
2015	58,450	49,802	260	N/A	1,855	4,541	N/A	4,281

*kW of lighting reduction

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	1.00	1.31	1,855	2,430
Summer kW Reduction	1.00	1.31	1,855	2,430
Annual kWh Reduction	4,380	4,774	8,124,900	8,855,770

	Annual
Utility Cost per Installation:	$108
Total Program Cost of the Utility ($000):	$200
Net Benefits of Measures Installed During Reporting Period:	($229,610)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Building Efficiency Program

Measure Name: Commercial Occupancy Sensor - Interior Lighting

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2010	54,648	46,618	300	N/A	...	...	N/A	...
2011	55,016	46,872	800	N/A	680	680	N/A	(120)
2012	55,584	47,317	1,400	N/A	1,171	1,851	N/A	451
2013	56,431	48,039	2,100	N/A	4,277	6,128	N/A	4,028
2014	57,460	48,940	2,850	N/A	3,650	9,778	N/A	6,928
2015	58,450	49,802	3,600	N/A	283	10,061	N/A	6,461

*Number of sensors installed

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.20	0.26	57	74
Summer kW Reduction	0.20	0.26	57	74
Annual kWh Reduction	800	872	226,400	246,776

	Annual
Utility Cost per Installation:	$8
Total Program Cost of the Utility ($000):	$2
Net Benefits of Measures Installed During Reporting Period:	($4,932)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Building Efficiency Program

Measure Name: Commercial Reflective Roof

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants* (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants* (Actual Participants)	Actual Cumulative Number of Program Participants* (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants* (Column G-Column D)
2010	54,648	46,618	100,000	N/A	...	...	N/A	...
2011	55,016	46,872	300,000	N/A	85,813	85,813	N/A	(214,187)
2012	55,584	47,317	600,000	N/A	424,855	510,668	N/A	(89,332)
2013	56,431	48,039	1,000,000	N/A	1,730,233	2,240,901	N/A	1,240,901
2014	57,460	48,940	1,400,000	N/A	533,691	2,774,592	N/A	1,374,592
2015	58,450	49,802	1,900,000	N/A	171,266	2,945,858	N/A	1,045,858

*Square feet of reflective roof installed

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.00	0.00	0	0
Summer kW Reduction	0.00091	0.0012	156	206
Annual kWh Reduction	2.45	2.67	419,602	457,280

	Annual
Utility Cost per Installation:	$0
Total Program Cost of the Utility ($000):	$13
Net Benefits of Measures Installed During Reporting Period:	($14,674)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Occupancy Sensor HVAC Control

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2010	54,648	46,618	75	N/A	...	...	N/A	...
2011	55,016	46,872	225	N/A	181	181	N/A	(44)
2012	55,584	47,317	425	N/A	330	511	N/A	86
2013	56,431	48,039	675	N/A	4,825	5,336	N/A	4,661
2014	57,460	48,940	925	N/A	82	5,418	N/A	4,493
2015	58,450	49,802	1,175	N/A	0	5,418	N/A	4,243

*Number of sensors installed

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.00012	0.00016	0	0
Summer kW Reduction	0.026	0.034	0	0
Annual kWh Reduction	512	558	0	0

	Annual	
Utility Cost per Installation:	N/A	
Total Program Cost of the Utility ($000):	$12	
Net Benefits of Measures Installed During Reporting Period:	N/A	No Program Participants

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: High Efficiency Motor Program

Measure Name: Commercial EE Motor 1-5 HP

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2010	54,648	46,618	25	N/A	...	...	N/A	...
2011	55,016	46,872	75	N/A	5	5	N/A	(70)
2012	55,584	47,317	125	N/A	6	11	N/A	(114)
2013	56,431	48,039	175	N/A	62	73	N/A	(102)
2014	57,460	48,940	225	N/A	17	90	N/A	(135)
2015	58,450	49,802	275	N/A	20	110	N/A	(165)

*Horespower installed

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.03	0.04	1	1
Summer kW Reduction	0.03	0.04	1	1
Annual kWh Reduction	159	173	3,180	3,460

	Annual
Utility Cost per Installation:	$44
Total Program Cost of the Utility ($000):	$0.89
Net Benefits of Measures Installed During Reporting Period:	($241)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: High Efficiency Motor Program

Measure Name: Commercial EE Motor 6-50 HP

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2010	54,648	46,618	1,000	N/A	...	...	N/A	...
2011	55,016	46,872	2,875	N/A	15	15	N/A	(2,860)
2012	55,584	47,317	4,750	N/A	412	427	N/A	(4,323)
2013	56,431	48,039	6,625	N/A	371	798	N/A	(5,827)
2014	57,460	48,940	8,500	N/A	325	1,123	N/A	(7,377)
2015	58,450	49,802	10,375	N/A	343	1,466	N/A	(8,909)

*Horespower installed

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.016	0.021	5	7
Summer kW Reduction	0.016	0.021	5	7
Annual kWh Reduction	94	102	32,242	34,986

	Annual
Utility Cost per Installation:	$8
Total Program Cost of the Utility ($000):	$3
Net Benefits of Measures Installed During Reporting Period:	($1,441)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: High Efficiency Motor Program

Measure Name: Commercial EE Motor 51 + HP

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2010	54,648	46,618	1,200	N/A	...	...	N/A	...
2011	55,016	46,872	3,600	N/A	300	300	N/A	(3,300)
2012	55,584	47,317	6,000	N/A	1,825	2,125	N/A	(3,875)
2013	56,431	48,039	8,400	N/A	0	2,125	N/A	(6,275)
2014	57,460	48,940	10,800	N/A	1,185	3,310	N/A	(7,490)
2015	58,450	49,802	13,200	N/A	260	3,570	N/A	(9,630)

*Horespower installed

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.006	0.008	2	2
Summer kW Reduction	0.006	0.008	2	2
Annual kWh Reduction	36	39	9,360	10,140

	Annual
Utility Cost per Installation:	$2
Total Program Cost of the Utility ($000):	$0
Net Benefits of Measures Installed During Reporting Period:	($381)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Food Service Efficiency Program

Measure Name: Convection Oven

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2010	54,648	46,618	1	0.00%	...	...	...	...
2011	55,016	46,872	4	0.01%	0	0	0.00%	(4)
2012	55,584	47,317	7	0.01%	8	8	0.02%	1
2013	56,431	48,039	10	0.02%	1	9	0.02%	(1)
2014	57,460	48,940	14	0.03%	1	10	0.02%	(4)
2015	58,450	49,802	18	0.04%	0	10	0.02%	(8)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.40	0.53	0	0
Summer kW Reduction	0.40	0.53	0	0
Annual kWh Reduction	1,869	2,037	0	0

	Annual	
Utility Cost per Installation:	N/A	
Total Program Cost of the Utility ($000):	$0	
Net Benefits of Measures Installed During Reporting Period:	N/A	No Program Participants

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Food Service Efficiency Program

Measure Name: Fryer

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	54,648	46,618	2	0.00%	...	...	...	...
2011	55,016	46,872	5	0.01%	0	0	0.00%	(5)
2012	55,584	47,317	9	0.02%	17	17	0.04%	8
2013	56,431	48,039	14	0.03%	9	26	0.05%	12
2014	57,460	48,940	20	0.04%	3	29	0.06%	9
2015	58,450	49,802	26	0.05%	12	41	0.08%	15

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.20	0.26	2	3
Summer kW Reduction	0.20	0.26	2	3
Annual kWh Reduction	1,160	1,264	13,920	15,168

	Annual
Utility Cost per Installation:	$201
Total Program Cost of the Utility ($000):	$2
Net Benefits of Measures Installed During Reporting Period:	($1,035)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Food Service Efficiency Program

Measure Name: Griddle

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2010	54,648	46,618	1	0.00%	...	...	...	...
2011	55,016	46,872	2	0.00%	0	0	0.00%	(2)
2012	55,584	47,317	3	0.01%	1	1	0.00%	(2)
2013	56,431	48,039	4	0.01%	0	1	0.00%	(3)
2014	57,460	48,940	5	0.01%	0	1	0.00%	(4)
2015	58,450	49,802	7	0.01%	1	2	0.00%	(5)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.50	0.66	1	1
Summer kW Reduction	0.50	0.66	1	1
Annual kWh Reduction	2,523	2,750	2,523	2,750

	Annual
Utility Cost per Installation:	$600
Total Program Cost of the Utility ($000):	$600
Net Benefits of Measures Installed During Reporting Period:	($171)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Food Service Efficiency Program

Measure Name: Steamer

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	54,648	46,618	0	0.00%	...	...	...	...
2011	55,016	46,872	0	0.00%	0	0	0.00%	0
2012	55,584	47,317	0	0.00%	0	0	0.00%	0
2013	56,431	48,039	1	0.00%	4	4	0.01%	3
2014	57,460	48,940	2	0.00%	1	5	0.01%	3
2015	58,450	49,802	3	0.01%	0	5	0.01%	2

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	13.79	18.11	0	0
Summer kW Reduction	13.79	18.11	0	0
Annual kWh Reduction	60,081	65,488	0	0

	Annual	
Utility Cost per Installation:	N/A	
Total Program Cost of the Utility ($000):	$0	
Net Benefits of Measures Installed During Reporting Period:	N/A	No Program Participants

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Food Service Efficiency Program

Measure Name: Holding Cabinet

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	54,648	46,618	5	0.01%	...	...	...	...
2011	55,016	46,872	11	0.02%	0	0	0.00%	(11)
2012	55,584	47,317	19	0.04%	2	2	0.00%	(17)
2013	56,431	48,039	27	0.06%	0	2	0.00%	(25)
2014	57,460	48,940	37	0.08%	2	4	0.01%	(33)
2015	58,450	49,802	47	0.09%	0	4	0.01%	(43)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	1.20	1.58	0	0
Summer kW Reduction	1.20	1.58	0	0
Annual kWh Reduction	6,534	7,122	0	0

	Annual	
Utility Cost per Installation:	N/A	
Total Program Cost of the Utility ($000):	$0	
Net Benefits of Measures Installed During Reporting Period:	N/A	No program participants

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Food Service Efficiency Program

Measure Name: Ice Machine

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	54,648	46,618	6	0.01%	...	...	...	...
2011	55,016	46,872	18	0.04%	0	0	0.00%	(18)
2012	55,584	47,317	30	0.06%	16	16	0.03%	(14)
2013	56,431	48,039	42	0.09%	6	22	0.05%	(20)
2014	57,460	48,940	54	0.11%	4	26	0.05%	(28)
2015	58,450	49,802	66	0.13%	12	38	0.08%	(28)
2016	59,469	50,692	78	0.15%				
2017	60,476	51,568	90	0.17%				
2018	61,486	52,443	102	0.19%				
2019	62,491	53,302	114	0.21%				

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.20	0.26	2	3
Summer kW Reduction	0.20	0.26	2	3
Annual kWh Reduction	1,797	1,959	21,564	23,508

	Annual
Utility Cost per Installation:	$103
Total Program Cost of the Utility ($000):	$1
Net Benefits of Measures Installed During Reporting Period:	($790)

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial/Industrial Custom Incentive

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	54,648	46,618	...	0.00%	...	...	...	...
2011	55,016	46,872	...	0.00%	6	6	0.01%	6
2012	55,584	47,317	...	0.00%	5	11	0.02%	11
2013	56,431	48,039	...	0.00%	4	15	0.03%	15
2014	57,460	48,940	...	0.00%	0	15	0.03%	15
2015	58,450	49,802	...	0.00%	0	15	0.03%	15

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	------	------	148	194
Summer kW Reduction	------	------	336	441
Annual kWh Reduction	------	------	1,965,492	2,142,385

	Annual
Utility Cost per Installation:	N/A
Total Program Cost of the Utility ($000):	$10
Net Benefits of Measures Installed During Reporting Period:	N/A

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial/Industrial Custom Incentive

Program Start Date: June, 2011

Reporting Period: Annual 2015

	Meter			Generator		
	Summer kW	**Winter kW**	**Energy kWh**	**Summer kW**	**Winter kW**	**Energy kWh**
2010	...	...	...	...	...	...
2011	440	443	3,985,873	577	582	5,234,646
2012	375	150	1,118,968	493	197	1,219,676
2013	336	148	1,965,492	441	194	2,142,385
2014	0	0	0	0	0	0
2015	0	0	0	0	0	0
Cumulative	1,151	741	7,070,333	1,511	973	8,596,707

Projects - 2013	Meter			Generator		
	Summer kW	**Winter kW**	**Energy kWh**	**Summer kW**	**Winter kW**	**Energy kWh**
General Electric	35.00	26.00	89,283	45.97	34.15	97,318
Baptist Hospital/Andrews Institute	238.00	95.00	1,449,959	312.57	124.76	1,580,455
Whiting Field	28.00	12.00	258,456	36.77	15.76	281,717
Whiting Field	35.00	15.00	167,794	45.97	19.70	182,895
Total	336.00	148.00	1,965,492	441.28	194.37	2,142,385

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Real Time Pricing

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C x 100)	**Actual Participation Over(Under) Projected Participation** (Column G-Column D)
2010	54,648	18	2	11.11%	...	...	...	...
2011	55,016	18	2	11.11%	0	0	0.00%	(2)
2012	55,584	18	2	11.11%	4	4	22.22%	2
2013	56,431	18	2	11.11%	0	4	22.22%	2
2014	57,460	18	2	11.11%	1	5	27.78%	3
2015	58,450	18	2	11.11%	1	6	33.33%	4

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	1,000	1,313	1,000	1,313
Summer kW Reduction	2,000	2,627	2,000	2,627
Annual kWh Reduction	------	------	------	------

	Annual	
Utility Cost per Installation:	$0	
Total Program Cost of the Utility ($000):	N/A	
Net Benefits of Measures Installed During Reporting Period:	N/A	No program participants

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Solar Thermal

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2010	374,936	373,219	115	0.03%	...	...	...	...
2011	377,336	375,619	230	0.06%	47	47	0.01%	(183)
2012	381,544	379,827	345	0.09%	36	83	0.02%	(262)
2013	388,378	386,661	460	0.12%	23	106	0.03%	(354)
2014	396,913	395,196	575	0.15%	27	133	0.03%	(442)
2015	405,062	403,345	575	0.14%	21	154	0.04%	(421)

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.25	0.33	5.25	6.93
Summer kW Reduction	0.25	0.33	5.25	6.93
Annual kWh Reduction	1,906	2,078	40,026.00	43,638.00

	Annual
Utility Cost per Installation:	$381
Total Program Cost of the Utility ($000):	$8
Net Benefits of Measures Installed During Reporting Period:	N/A

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Solar PV

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2010	374,936	373,219	40	0.01%	...	...	...	...
2011	377,336	375,619	80	0.02%	41	41	0.01%	(39)
2012	381,544	379,827	120	0.03%	44	85	0.02%	(35)
2013	388,378	386,661	160	0.04%	42	127	0.03%	(33)
2014	396,913	395,196	200	0.05%	42	169	0.04%	(31)
2015	405,062	403,345	200	0.05%	47	216	0.05%	16

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	1.50	1.97	70.50	92.59
Summer kW Reduction	3.00	3.94	141.00	185.18
Annual kWh Reduction	6,388	6,963	300,236.00	327,261.00

	Annual
Utility Cost per Installation:	$5,142
Total Program Cost of the Utility ($000):	$242
Net Benefits of Measures Installed During Reporting Period:	N/A

DSM PROGRAM PROGRESS REPORT
(2010 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Solar PV

Program Start Date: June, 2011

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2010	54,648	46,618	6	0.01%	...	...	...	...
2011	55,016	46,872	12	0.03%	1	1	0.00%	(11)
2012	55,584	47,317	18	0.04%	3	4	0.01%	(14)
2013	56,431	48,039	24	0.05%	3	7	0.01%	(17)
2014	57,460	48,940	30	0.06%	8	15	0.03%	(15)
2015	58,450	49,802	30	0.06%	5	20	0.04%	(10)

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	1.50	1.97	7.50	9.85
Summer kW Reduction	3.00	3.94	15.00	19.70
Annual kWh Reduction	6,388	6,963	31,940.00	34,815.00

	Annual
Utility Cost per Installation:	$48,336
Total Program Cost of the Utility ($000):	$242
Net Benefits of Measures Installed During Reporting Period:	N/A

GULF POWER COMPANY
2015 DSM Progress Report
Savings at the Meter
2010 DSM PLAN

		A	B	C	D	E	F	G	H	I	J
		Total	Per Unit	Per Unit	Per Unit	Total	Total	Total	Cumulative	Cumulative	Cumulative
Residential Programs	**Measures**	Units	Win. kW	Sum. kW	kWh	Win. MW	Sum. MW	GWh	Win. MW	Sum. MW	GWh
Residential Energy Audit and Education	Home Energy Reporting	0	0.06	0.06	300	0.00	0.00	0.00	2.35	2.35	11.75
Community Energy Saver	Residential Community Energy Saver	1,737	0.11	0.05	736	0.19	0.09	1.28	1.27	0.58	8.45
Landlord/Renter Custom Incentive	Landlord/Renter Customer Incentive Program	0	------	------	------	0.00	0.00	0.00	0.00	0.12	0.29
HVAC Efficiency Improvement	Residential HVAC Maintenance	5,708	0.26	0.31	1,306	1.48	1.77	7.45	8.26	9.85	41.49
HVAC Efficiency Improvement	Residential HVAC Early Retirement Tier 1	1,099	1.16	1.24	5,854	1.27	1.36	6.43	5.03	5.39	25.42
HVAC Efficiency Improvement	Residential HVAC Early Retirement Tier 2	770	1.25	1.33	6,243	0.96	1.02	4.81	3.68	3.93	18.44
HVAC Efficiency Improvement	Residential HVAC Early Retirement Tier 3	39	1.67	1.57	7,132	0.07	0.06	0.28	0.29	0.25	1.18
HVAC Efficiency Improvement	Residential HVAC Efficiency Upgrade Tier 1	249	0.43	0.32	1,567	0.11	0.08	0.39	0.45	0.34	1.66
HVAC Efficiency Improvement	Residential HVAC Efficiency Upgrade Tier 2	120	0.47	0.40	1,891	0.06	0.05	0.23	0.31	0.26	1.25
HVAC Efficiency Improvement	Residential HVAC Efficiency Upgrade Tier 3	73	1.08	0.64	3,456	0.08	0.05	0.25	0.43	0.25	1.35
HVAC Efficiency Improvement	Residential Duct Repair	3,965	0.21	0.32	1,382	0.83	1.27	5.48	4.23	6.44	27.81
HVAC Efficiency Improvement	Residential ECM Fan	0	0.14	0.27	1,109	0.00	0.00	0.00	0.00	0.00	0.00
Heat Pump Water Heater	Residential HPWH	298	0.37	0.10	1,348	0.11	0.03	0.40	1.45	0.40	5.32
Ceiling Insulation	Residential Ceiling Insulation	338	0.80	0.10	575	0.27	0.03	0.19	1.84	0.23	1.32
High Performance Window	Residential Window Replacement	511	0.50	0.20	1,338	0.26	0.10	0.68	1.83	0.73	4.87
High Performance Window	Residential Window Film	96	0.00	0.20	788	0.00	0.02	0.08	0.00	0.11	0.44
Reflective Roof	Residential Reflective Roof	155	0.00	0.41	1,029	0.00	0.06	0.16	0.00	0.41	1.06
Variable Speed/Flow Pool Pump	Variable Speed/Flow Pool Pump	223	1.15	1.15	2,494	0.26	0.26	0.56	7.32	7.32	15.88
Energy Select	Energy Select	1,394	2.20	1.73	762	3.07	2.41	1.06	9.27	7.29	3.21
Energy Select Lite	Energy Select Lite	0	1.10	0.98	556	0.00	0.00	0.00	3.53	3.14	1.78
Self-Install Energy Efficiency	Residential Energy Star Refrigerator	657	0.03	0.04	271	0.02	0.03	0.18	0.20	0.26	1.78
Self-Install Energy Efficiency	Residential Energy Star Freezer	37	0.01	0.01	82	0.00	0.00	0.00	0.00	0.00	0.03
Self-Install Energy Efficiency	Residential Energy Star Window A/C	234	0.00	0.22	432	0.00	0.05	0.10	0.00	0.16	0.33
Self-Install Energy Efficiency	Residential Energy Star Clothes Washer	685	0.03	0.03	197	0.02	0.02	0.13	0.18	0.18	1.25
Self-Install Energy Efficiency	Residential CFL	0	0.00	0.00	55	0.00	0.00	0.00	0.27	0.19	4.45
Refrigerator Recycling	Residential Refrigerator Recycling	0	0.08	0.08	738	0.00	0.00	0.00	0.31	0.31	2.78
			Total Residential Applicable To Goal			**9.06**	**8.76**	**30.14**	**52.50**	**50.49**	**183.59**
Residential Energy Audit and Education	Residential Energy Audit	5,137	------	------	------	-----	-----	-----	-----	-----	-----
					Total Residential	**9.06**	**8.76**	**30.14**	**52.50**	**50.49**	**183.59**
Commercial and Industrial Programs	**Measures**										
Commercial HVAC Retrocommissioning	Commercial HVAC Retrocommissioning	17	0.32	1.30	3,921	0.01	0.02	0.07	0.31	1.25	3.79
Commercial Building Efficiency	Commercial HVAC Program	1,296	0.00	0.15	652	0.00	0.19	0.84	0.00	1.09	4.78
Commercial Building Efficiency	Commercial Geothermal Heat Pump Program	0	0.27	0.29	685	0.00	0.00	0.00	0.13	0.14	0.34
Commercial Building Efficiency	Commercial HPWH Program	0	11.80	10.00	41,241	0.00	0.00	0.00	0.03	0.03	0.12
Commercial Building Efficiency	Commercial Ceiling/Roof Insulation Program	8,511	0.00	0.00	1	0.00	0.00	0.01	0.03	0.15	0.26
Commercial Building Efficiency	Commercial Window Film	2,503	0.00	0.00	11	0.00	0.01	0.03	0.00	0.12	0.40
Commercial Building Efficiency	Commercial Interior Lighting	164	1.00	1.00	4,380	0.16	0.16	0.72	2.53	2.53	11.07
Commercial Building Efficiency	Commercial Interior Lighting - LED	1,855	1.00	1.00	4,380	1.86	1.86	8.12	4.55	4.55	19.89
Commercial Building Efficiency	Commercial Occupancy Sensor - Interior Lighting	283	0.20	0.20	800	0.06	0.06	0.23	2.02	2.02	8.05
Commercial Building Efficiency	Commercial Reflective Roof	171,266	0.00	0.00	2	0.00	0.16	0.42	0.00	2.69	7.22
Occupancy Sensor HVAC Control	Commercial Occupancy Sensor - HVAC	0	0.00	0.03	512	0.00	0.00	0.00	0.00	0.14	2.77
High Efficiency Motor	Commercial EE Motor 1-5 HP	20	0.03	0.03	159	0.00	0.00	0.00	0.00	0.00	0.01
High Efficiency Motor	Commercial EE Motor 6-50 HP	343	0.02	0.02	94	0.01	0.01	0.03	0.04	0.04	0.13
High Efficiency Motor	Commercial EE Motor 51 + HP	260	0.01	0.01	36	0.00	0.00	0.01	0.02	0.02	0.13
Food Service Efficiency	Convection Oven	0	0.40	0.40	1,869	0.00	0.00	0.00	0.00	0.00	0.01
Food Service Efficiency	Fryer	12	0.20	0.20	1,160	0.00	0.00	0.01	0.00	0.00	0.04
Food Service Efficiency	Griddle	1	0.50	0.50	2,523	0.00	0.00	0.00	0.00	0.00	0.00
Food Service Efficiency	Steamer	0	13.79	13.79	60,081	0.00	0.00	0.00	0.07	0.07	0.30
Food Service Efficiency	Holding Cabinet	0	1.20	1.20	6,534	0.00	0.00	0.00	0.00	0.00	0.02
Food Service Efficiency	Ice Machine	12	0.20	0.20	1,797	0.00	0.00	0.02	0.00	0.00	0.07
Commercial/Industrial Custom Incentive	Commercial/Industrial Custom Incentive	0	------	------	------	0.15	0.34	1.97	1.04	1.84	11.02
Real Time Pricing	Real Time Pricing	1	1,000	2,000	------	1.00	2.00	------	6.00	12.00	------
		Total Commercial/Industrial Applicable to Goal				**3.25**	**4.81**	**12.48**	**16.77**	**28.68**	**70.42**
Commercial/Industrial Energy Analysis	Commercial/Industrial Energy Analysis	327	------	------	------	-----	-----	-----	-----	-----	-----
					Total Commercial/Industrial	**3.25**	**4.81**	**12.48**	**16.77**	**28.68**	**70.42**
Solar Programs	**Measures**										
Residential Solar Thermal	Residential Solar Thermal	21	0.25	0.25	1,906	0.01	0.01	0.04	0.05	0.05	0.30
Residential Solar PV	Residential Solar PV	47	1.50	3.00	6,388	0.07	0.14	0.30	0.32	0.66	1.39
Commercial Solar PV	Commercial Solar PV	5	1.50	3.00	6,388	0.01	0.02	0.03	0.02	0.05	0.12
			Total Solar Programs			**0.09**	**0.17**	**0.37**	**0.39**	**0.76**	**1.81**

Column A:	Actual acheived for the reporting year.
Column B:	As filed in the Conservation Plan Filing
Column C:	As filed in the Conservation Plan Filing
Column D:	As filed in the Conservation Plan Filing
Column E:	(Column A) X (Column B)
Column F:	(Column A) X (Column C)
Column G:	(Column A) X (Column D)
Column H:	Annual Results plus any/all previous Annual Results for this conservation plan.
Column I:	Annual Results plus any/all previous Annual Results for this conservation plan.
Column J:	Annual Results plus any/all previous Annual Results for this conservation plan.

GULF POWER COMPANY

2015 DSM Progress Report
Savings at the Generator

2010 DSM PLAN

Residential Programs	Measures	A Total Units	B Per Unit Win. kW	C Per Unit Sum. kW	D Per Unit kWh	E Total Win. MW	F Total Sum. MW	G Total GWh	H Cumulative Win. MW	I Cumulative Sum. MW	J Cumulative GWh
Residential Energy Audit and Education	Home Energy Reporting	0	0.08	0.08	327	0.00	0.00	0.00	3.13	3.13	12.81
Community Energy Saver	Residential Community Energy Saver	1,737	0.14	0.07	802	0.24	0.12	1.39	1.61	0.80	9.22
Landlord/Renter Custom Incentive	Landlord/Renter Customer Incentive Program	0	------	------	------	0.00	0.00	0.00	0.00	0.16	0.38
HVAC Efficiency Improvement	Residential HVAC Maintenance	5,708	0.34	0.41	1,424	1.94	2.34	8.13	10.81	13.02	45.23
HVAC Efficiency Improvement	Residential HVAC Early Retirement Tier 1	1,099	1.52	1.63	6,381	1.67	1.79	7.01	6.60	7.08	27.71
HVAC Efficiency Improvement	Residential HVAC Early Retirement Tier 2	770	1.64	1.75	6,805	1.26	1.35	5.24	4.85	5.17	20.11
HVAC Efficiency Improvement	Residential HVAC Early Retirement Tier 3	39	2.19	2.06	7,774	0.09	0.08	0.30	0.37	0.33	1.29
HVAC Efficiency Improvement	Residential HVAC Efficiency Upgrade Tier 1	249	0.56	0.42	1,708	0.14	0.10	0.43	0.60	0.44	1.82
HVAC Efficiency Improvement	Residential HVAC Efficiency Upgrade Tier 2	120	0.62	0.53	2,061	0.07	0.06	0.25	0.40	0.35	1.35
HVAC Efficiency Improvement	Residential HVAC Efficiency Upgrade Tier 3	73	1.42	0.84	3,767	0.10	0.06	0.27	0.54	0.32	1.47
HVAC Efficiency Improvement	Residential Duct Repair	3,965	0.28	0.42	1,506	1.11	1.67	5.97	5.64	8.45	30.31
HVAC Efficiency Improvement	Residential ECM Fan	0	0.18	0.35	1,209	0.00	0.00	0.00	0.00	0.00	0.00
Heat Pump Water Heater	Residential HPWH	298	0.49	0.13	1,469	0.15	0.04	0.44	1.94	0.51	5.81
Ceiling Insulation	Residential Ceiling Insulation	338	1.05	0.13	627	0.35	0.04	0.21	2.39	0.30	1.44
High Performance Window	Residential Window Replacement	511	0.66	0.26	1,458	0.34	0.13	0.75	2.40	0.94	5.32
High Performance Window	Residential Window Film	96	0.00	0.26	859	0.00	0.02	0.08	0.00	0.14	0.47
Reflective Roof	Residential Reflective Roof	155	0.00	0.54	1,122	0.00	0.08	0.17	0.00	0.55	1.15
Variable Speed/Flow Pool Pump	Variable Speed/Flow Pool Pump	223	1.51	1.51	2,718	0.34	0.34	0.61	9.61	9.61	17.29
Energy Select	Energy Select	1,394	2.89	2.27	831	4.03	3.17	1.16	12.18	9.57	3.50
Energy Select Lite	Energy Select Lite	0	1.44	1.29	606	0.00	0.00	0.00	4.63	4.13	1.94
Self-Install Energy Efficiency	Residential Energy Star Refrigerator	657	0.04	0.05	295	0.03	0.03	0.19	0.26	0.33	1.93
Self-Install Energy Efficiency	Residential Energy Star Freezer	37	0.01	0.01	89	0.00	0.00	0.00	0.00	0.00	0.04
Self-Install Energy Efficiency	Residential Energy Star Window A/C	234	0.00	0.29	471	0.00	0.07	0.11	0.00	0.22	0.36
Self-Install Energy Efficiency	Residential Energy Star Clothes Washer	685	0.04	0.04	215	0.03	0.03	0.15	0.24	0.24	1.37
Self-Install Energy Efficiency	Residential CFL	0	0.00	0.00	60	0.00	0.00	0.00	0.35	0.25	4.85
Refrigerator Recycling	Residential Refrigerator Recycling	0	0.11	0.11	804	0.00	0.00	0.00	0.39	0.39	3.04
					Total Residential Applicable To Goal	**11.89**	**11.52**	**32.86**	**68.94**	**66.43**	**200.21**
Residential Energy Audit and Education	Residential Energy Audit	5,137	------	------	------	-----	-----	-----	-----	-----	-----
					Total Residential	**11.89**	**11.52**	**32.86**	**68.94**	**66.43**	**200.21**

Commercial and Industrial Programs	Measures	A	B	C	D	E	F	G	H	I	J
Commercial HVAC Retrocommissioning	Commercial HVAC Retrocommissioning	17	0.42	1.71	4,274	0.01	0.03	0.07	0.42	1.64	4.12
Commercial Building Efficiency	Commercial HVAC Program	1,296	0.00	0.20	711	0.00	0.26	0.92	0.00	1.47	5.20
Commercial Building Efficiency	Commercial Geothermal Heat Pump Program	0	0.35	0.38	747	0.00	0.00	0.00	0.17	0.19	0.37
Commercial Building Efficiency	Commercial HPWH Program	0	15.50	13.10	44,953	0.00	0.00	0.00	0.06	0.03	0.12
Commercial Building Efficiency	Commercial Ceiling/Roof Insulation Program	8,511	0.00	0.00	1	0.00	0.01	0.01	0.04	0.21	0.27
Commercial Building Efficiency	Commercial Window Film	2,503	0.00	0.00	12	0.00	0.01	0.03	0.00	0.15	0.44
Commercial Building Efficiency	Commercial Interior Lighting	164	1.31	1.31	4,774	0.21	0.21	0.78	3.31	3.31	12.05
Commercial Building Efficiency	Commercial Interior Lighting - LED	1,855	1.31	1.31	4,774	2.43	2.43	8.86	5.96	5.96	21.68
Commercial Building Efficiency	Commercial Occupancy Sensor - Interior Lighting	283	0.26	0.26	872	0.07	0.07	0.25	2.61	2.61	8.77
Commercial Building Efficiency	Commercial Reflective Roof	171,266	0.00	0.00	3	0.00	0.21	0.46	0.00	3.54	7.86
Occupancy Sensor HVAC Control	Commercial Occupancy Sensor - HVAC	0	0.00	0.03	558	0.00	0.00	0.00	0.00	0.18	3.02
High Efficiency Motor	Commercial EE Motor 1-5 HP	20	0.04	0.04	173	0.00	0.00	0.00	0.00	0.00	0.01
High Efficiency Motor	Commercial EE Motor 6-50 HP	343	0.02	0.02	102	0.01	0.01	0.03	0.04	0.04	0.14
High Efficiency Motor	Commercial EE Motor 51 + HP	260	0.01	0.01	39	0.00	0.00	0.01	0.02	0.02	0.14
Food Service Efficiency	Convection Oven	0	0.53	0.53	2,037	0.00	0.00	0.00	0.00	0.00	0.02
Food Service Efficiency	Fryer	12	0.26	0.26	1,264	0.00	0.00	0.02	0.00	0.00	0.05
Food Service Efficiency	Griddle	1	0.66	0.66	2,750	0.00	0.00	0.00	0.00	0.00	0.00
Food Service Efficiency	Steamer	0	18.11	18.11	65,488	0.00	0.00	0.00	0.09	0.09	0.33
Food Service Efficiency	Holding Cabinet	0	1.58	1.58	7,122	0.00	0.00	0.00	0.00	0.00	0.02
Food Service Efficiency	Ice Machine	12	0.26	0.26	1,959	0.00	0.00	0.02	0.00	0.00	0.07
Commercial/Industrial Custom Incentive	Commercial/Industrial Custom Incentive	0	------	------	------	0.19	0.44	2.14	1.35	2.39	12.87
Real Time Pricing	Real Time Pricing	1	1,313	2,627	------	1.31	2.63	------	7.87	15.77	------
					Total Commercial/Industrial Applicable to Goal	**4.23**	**6.31**	**13.60**	**21.94**	**37.60**	**77.55**
Commercial/Industrial Energy Analysis	Commercial/Industrial Energy Analysis	327	------	------	------	-----	-----	-----	-----	-----	-----
					Total Commercial/Industrial	**4.23**	**6.31**	**13.60**	**21.94**	**37.60**	**77.55**

Solar Programs	Measures	A	B	C	D	E	F	G	H	I	J
Residential Solar Thermal	Residential Solar Thermal	21	0.33	0.33	2,078	0.01	0.01	0.04	0.06	0.06	0.33
Residential Solar PV	Residential Solar PV	47	1.97	3.94	6,963	0.09	0.19	0.33	0.42	0.87	1.51
Commercial Solar PV	Commercial Solar PV	5	1.97	3.94	6,963	0.01	0.02	0.03	0.04	0.06	0.13
					Total Solar Programs	**0.11**	**0.22**	**0.40**	**0.52**	**0.99**	**1.97**

Column A:	Actual acheived for the reporting year.
Column B:	As filed in the Conservation Plan Filing
Column C:	As filed in the Conservation Plan Filing
Column D:	As filed in the Conservation Plan Filing
Column E:	(Column A) X (Column B)
Column F:	(Column A) X (Column C)
Column G:	(Column A) X (Column D)
Column H:	Annual Results plus any/all previous Annual Results for this conservation plan.
Column I:	Annual Results plus any/all previous Annual Results for this conservation plan.
Column J:	Annual Results plus any/all previous Annual Results for this conservation plan.

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Energy Audit and Education

Measure Name: Residential Energy Audit

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G - Column D)
2015	392,015	390,238	8,400	2.15%	2,301	2,301	0.59%	(6,099)
2016	397,625	395,848	16,800	4.24%				
2017	404,186	402,409	25,200	6.26%				
2018	410,463	408,686	33,600	8.22%				
2019	416,121	414,344	42,000	10.14%				
2020	421,420	419,643	50,400	12.01%				
2021	125,977	424,200	58,800	13.86%				
2022	429,938	428,161	67,200	15.70%				
2023	433,642	431,865	75,600	17.51%				
2024	436,925	435,148	84,000	19.30%				

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	------	------	------	------
Summer kW Reduction	------	------	------	------
Annual kWh Reduction	------	------	------	------

	Annual
Utility Cost per Installation:	$302
Total Program Cost of the Utility ($000):	$695
Net Benefits of Measures Installed During Reporting Period:	N/A

Note: The demand and energy savings of this program are not applied toward the established DSM goals.

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Community Energy Saver

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2015	374,936	130,627	2,500	1.91%	149	149	0.11%	(2,351)
2016	377,336	131,467	5,000	3.80%				
2017	381,544	132,939	7,500	5.64%				
2018	388,378	135,331	10,000	7.39%				
2019	396,913	138,319	12,500	9.04%				
2020	405,062	141,171	15,000	10.63%				
2021	416,491	144,121	17,500	12.14%				
2022	421,774	147,020	20,000	13.60%				
2023	430,056	149,919	22,500	15.01%				
2024	438,190	152,766	25,000	16.36%				

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.11	0.14	16	21
Summer kW Reduction	0.05	0.06	7	9
Annual kWh Reduction	769	810	114,581	120,690

	Annual
Utility Cost per Installation:	$1,789
Total Program Cost of the Utility ($000):	$267
Net Benefits of Measures Installed During Reporting Period:	($31,617)

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Landlord-Renter Custom Incentive

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2015	374,936	130,627	0	0.00%	0	0	0.00%	0
2016	377,336	131,467	0	0.00%				
2017	381,544	132,939	0	0.00%				
2018	388,378	135,331	0	0.00%				
2019	396,913	138,319	0	0.00%				
2020	405,062	141,171	0	0.00%				
2021	416,491	144,121	0	0.00%				
2022	421,774	147,020	0	0.00%				
2023	430,056	149,919	0	0.00%				
2024	438,190	152,766	0	0.00%				

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	------	------	0	0
Summer kW Reduction	------	------	0	0
Annual kWh Reduction	------	------	0	0

	Annual	
Utility Cost per Installation:	N/A	
Total Program Cost of the Utility ($000):	$4	
Net Benefits of Measures Installed During Reporting Period:	N/A	No incentives paid

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Landlord/Renter Custom Incentive Program

Program Start Date: September, 2015

Reporting Period: Annual 2015 0

	Meter			Generator		
	Summer kW	Winter kW	Energy kWh	Summer kW	Winter kW	Energy kWh
2015	**0**	**0**	**0**	**0**	**0**	**0**
2016						
2017						
2018						
2019						
Cumulative	0	0	0	0	0	0

Projects - 2015	Meter			Generator		
	Summer kW	Winter kW	Energy kWh	Summer kW	Winter kW	Energy kWh
Total	0.00	0.00	0	0.00	0.00	0

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential HVAC Efficiency Improvement Program

Measure Name: Residential HVAC Maintenance

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants **Plan-To-Date)**	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2015	392,015	390,238	800	0.21%	999	999	0.26%	199
2016	397,625	395,848	2,000	0.51%				
2017	404,186	402,409	4,000	0.99%				
2018	410,463	408,686	7,200	1.76%				
2019	416,121	414,344	10,600	2.56%				
2020	421,420	419,643	14,400	3.43%				
2021	425,977	424,200	18,600	4.38%				
2022	429,938	428,161	23,200	5.42%				
2023	433,642	431,865	28,050	6.50%				
2024	436,925	435,148	33,050	7.60%				

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.07	0.08	70	80
Summer kW Reduction	0.24	0.29	240	290
Annual kWh Reduction	607	639	606,393	638,361

	Annual
Utility Cost per Installation:	$364
Total Program Cost of the Utility ($000):	$364
Net Benefits of Measures Installed During Reporting Period:	($44,296)

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential HVAC Efficiency Improvement Program

Measure Name: Residential HVAC Quality Installation

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2015	392,015	390,238	2,000	0.51%	0	0	0.00%	(2,000)
2016	397,625	395,848	4,000	1.01%				
2017	404,186	402,409	6,000	1.49%				
2018	410,463	408,686	8,500	2.08%				
2019	416,121	414,344	12,000	2.90%				
2020	421,420	419,643	16,500	3.93%				
2021	425,977	424,200	21,500	5.07%				
2022	429,938	428,161	26,500	6.19%				
2023	433,642	431,865	31,500	7.29%				
2024	436,925	435,148	36,500	8.39%				

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.08	0.10	0	0
Summer kW Reduction	0.18	0.22	0	0
Annual kWh Reduction	451	475	0	0

	Annual
Utility Cost per Installation:	N/A
Total Program Cost of the Utility ($000):	$222
Net Benefits of Measures Installed During Reporting Period:	N/A

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential HVAC Efficiency Improvement Program

Measure Name: Residential Duct Repair

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2015	392,015	390,238	500	0.13%	0	0	0.00%	(500)
2016	397,625	395,848	1,000	0.25%				
2017	404,186	402,409	1,500	0.37%				
2018	410,463	408,686	2,000	0.49%				
2019	416,121	414,344	3,500	0.84%				
2020	421,420	419,643	5,500	1.31%				
2021	425,977	424,200	8,000	1.89%				
2022	429,938	428,161	11,000	2.57%				
2023	433,642	431,865	14,500	3.36%				
2024	436,925	435,148	18,500	4.25%				

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	1.11	1.37	0	0
Summer kW Reduction	0.15	0.18	0	0
Annual kWh Reduction	303	319	0	0

	Annual
Utility Cost per Installation:	N/A
Total Program Cost of the Utility ($000):	$182
Net Benefits of Measures Installed During Reporting Period:	N/A

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Building Efficiency Program

Measure Name: Residential High Performance Window

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2015	392,015	390,238	250	0.06%	251	251	0.06%	1
2016	397,625	395,848	600	0.15%				
2017	404,186	402,409	1,050	0.26%				
2018	410,463	408,686	1,550	0.38%				
2019	416,121	414,344	2,150	0.52%				
2020	421,420	419,643	2,850	0.68%				
2021	425,977	424,200	3,650	0.86%				
2022	429,938	428,161	4,650	1.09%				
2023	433,642	431,865	5,850	1.35%				
2024	436,925	435,148	7,250	1.67%				

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.24	0.30	60	75
Summer kW Reduction	0.21	0.26	53	65
Annual kWh Reduction	391	412	98,141	103,412

	Annual
Utility Cost per Installation:	$151
Total Program Cost of the Utility ($000):	$38
Net Benefits of Measures Installed During Reporting Period:	($4,674)

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Building Efficiency Program

Measure Name: Residential Reflective Roof

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2015	392,015	390,238	100	0.03%	60	60	0.02%	(40)
2016	397,625	395,848	250	0.06%				
2017	404,186	402,409	450	0.11%				
2018	410,463	408,686	700	0.17%				
2019	416,121	414,344	1,000	0.24%				
2020	421,420	419,643	1,350	0.32%				
2021	425,977	424,200	1,750	0.41%				
2022	429,938	428,161	2,250	0.53%				
2023	433,642	431,865	2,850	0.66%				
2024	436,925	435,148	3,550	0.82%				

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.00	0.00	0	0
Summer kW Reduction	0.41	0.50	25	30
Annual kWh Reduction	1,029	1,084	61,740	65,040

	Annual
Utility Cost per Installation:	$0
Total Program Cost of the Utility ($000):	$0
Net Benefits of Measures Installed During Reporting Period:	($2,313)

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Energy Select (formerly GoodCents Select)

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2015	392,015	390,238	1,600	0.41%	472	472	0.12%	(1,128)
2016	397,625	395,848	3,200	0.81%				
2017	404,186	402,409	4,800	1.19%				
2018	410,463	408,686	6,400	1.57%				
2019	416,121	414,344	8,000	1.93%				
2020	421,420	419,643	9,750	2.32%				
2021	425,977	424,200	11,650	2.75%				
2022	429,938	428,161	13,700	3.20%				
2023	433,642	431,865	15,900	3.68%				
2024	436,925	435,148	18,250	4.19%				

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	1.07	1.32	505	623
Summer kW Reduction	1.80	2.22	850	1,048
Annual kWh Reduction	735	774	346,920	365,328

	Annual
Utility Cost per Installation:	$3,175
Total Program Cost of the Utility ($000):	$1,499
Net Benefits of Measures Installed During Reporting Period:	($1,603,082)

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Residential Building Efficiency Program

Measure Name: Residential Energy Star Window A/C

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	Total Number of Customers (From Cons. Plan)	Total Number of Eligible Customers (From Cons. Plan)	Projected Cumulative Number of Program Participants (From Cons. Plan)	Projected Cumulative Penetration Level % (D/C X 100)	Actual Annual Number of Program Participants (Actual Participants)	Actual Cumulative Number of Program Participants (Actual Participants Plan-To-Date)	Actual Cumulative Penetration Level % (G/C X 100)	Actual Participation Over (Under) Projected Participants (Column G-Column D)
2015	392,015	390,238	200	0.05%	1	1	0.00%	(199)
2016	397,625	395,848	400	0.10%				
2017	404,186	402,409	600	0.15%				
2018	410,463	408,686	800	0.20%				
2019	416,121	414,344	1,000	0.24%				
2020	421,420	419,643	1,200	0.29%				
2021	425,977	424,200	1,400	0.33%				
2022	429,938	428,161	1,600	0.37%				
2023	433,642	431,865	1,800	0.42%				
2024	436,925	435,148	2,000	0.46%				

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.00	0.00	0	0
Summer kW Reduction	0.04	0.05	0	0
Annual kWh Reduction	82	86	82	86

	Annual
Utility Cost per Installation:	$2,454
Total Program Cost of the Utility ($000):	$2
Net Benefits of Measures Installed During Reporting Period:	($222)

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial/Industrial Energy Audit

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2015	55,525	47,673	500	1.05%	125	125	0.26%	(375)
2016	55,992	48,140	1,000	2.08%				
2017	56,539	48,687	1,500	3.08%				
2018	57,062	49,210	2,000	4.06%				
2019	57,534	49,682	2,500	5.03%				
2020	57,975	50,123	3,000	5.99%				
2021	58,355	50,203	3,500	6.97%				
2022	58,683	50,831	4,000	7.87%				
2023	58,992	51,140	4,500	8.80%				
2024	59,264	51,412	5,000	9.73%				

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	------	------	------	------
Summer kW Reduction	------	------	------	------
Annual kWh Reduction	------	------	------	------

	Annual
Utility Cost per Installation:	$1,723
Total Program Cost of the Utility ($000):	$215
Net Benefits of Measures Installed During Reporting Period:	N/A

Note: The demand and energy savings of this program are not applied toward the established DSM goals.

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial HVAC Retrocommissioning

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2015	55,525	47,673	250	0.52%	5	5	0.01%	(245)
2016	55,992	48,140	500	1.04%				
2017	56,539	48,687	750	1.54%				
2018	57,062	49,210	1,000	2.03%				
2019	57,534	49,682	1,250	2.52%				
2020	57,975	50,123	1,500	2.99%				
2021	58,355	50,203	1,775	3.54%				
2022	58,683	50,831	2,100	4.13%				
2023	58,992	51,140	2,450	4.79%				
2024	59,264	51,412	2,825	5.49%				

Annual Demand and Energy Savings	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Winter kW Reduction	0.00	0.00	0	0
Summer kW Reduction	0.30	0.37	2	2
Annual kWh Reduction	965	1,016	4,825	5,080

	Annual
Utility Cost per Installation:	$1,896
Total Program Cost of the Utility ($000):	$9
Net Benefits of Measures Installed During Reporting Period:	($935)

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Building Efficiency Program

Measure Name: Commercial Geothermal Heat Pump Program

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2015	55,525	47,673	120	N/A	37	37	N/A	(83)
2016	55,992	48,140	245	N/A				
2017	56,539	48,687	375	N/A				
2018	57,062	49,210	515	N/A				
2019	57,534	49,682	665	N/A				
2020	57,975	50,123	865	N/A				
2021	58,355	50,203	1,075	N/A				
2022	58,683	50,831	1,300	N/A				
2023	58,992	51,140	1,530	N/A				
2024	59,264	51,412	1,765	N/A				

*Tons of Geothermal HVAC installed

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.27	0.33	10	12
Summer kW Reduction	0.29	0.36	11	13
Annual kWh Reduction	685	721	25,345	26,677

	Annual
Utility Cost per Installation:	$0
Total Program Cost of the Utility ($000):	$0
Net Benefits of Measures Installed During Reporting Period:	($777)

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Building Efficiency Program

Measure Name: Commercial Ceiling/Roof Insulation Program

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2015	55,525	47,673	225,000	N/A	20,555	20,555	N/A	(204,445)
2016	55,992	48,140	475,000	N/A				
2017	56,539	48,687	750,000	N/A				
2018	57,062	49,210	1,050,000	N/A				
2019	57,534	49,682	1,450,000	N/A				
2020	57,975	50,123	1,850,000	N/A				
2021	58,355	50,203	2,300,000	N/A				
2022	58,683	50,831	2,800,000	N/A				
2023	58,992	51,140	3,350,000	N/A				
2024	59,264	51,412	3,950,000	N/A				

*Square feet of insulation installed

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.00012	0.00015	2	3
Summer kW Reduction	0.00046	0.00057	9	12
Annual kWh Reduction	0.748	0.80	15,375	16,444

	Annual
Utility Cost per Installation:	$0
Total Program Cost of the Utility ($000):	$3
Net Benefits of Measures Installed During Reporting Period:	($138)

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial Building Efficiency Program

Measure Name: Commercial Reflective Roof

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants*** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants*** (Actual Participants)	**Actual Cumulative Number of Program Participants*** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants*** (Column G-Column D)
2015	55,525	47,673	800,000	N/A	59,300	59,300	N/A	(740,700)
2016	55,992	48,140	1,600,000	N/A				
2017	56,539	48,687	2,400,000	N/A				
2018	57,062	49,210	3,200,000	N/A				
2019	57,534	49,682	4,000,000	N/A				
2020	57,975	50,123	4,850,000	N/A				
2021	58,355	50,203	5,750,000	N/A				
2022	58,683	50,831	6,700,000	N/A				
2023	58,992	51,140	7,700,000	N/A				
2024	59,264	51,412	8,750,000	N/A				

*Square feet of reflective roof installed

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.00	0.00	0	0
Summer kW Reduction	0.00067	0.0008	40	47
Annual kWh Reduction	1.72	1.81	101,996	107,333

	Annual
Utility Cost per Installation:	$0
Total Program Cost of the Utility ($000):	$0
Net Benefits of Measures Installed During Reporting Period:	($549)

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial/Industrial Custom Incentive

Program Start Date: September, 2015

Reporting Period: Annual 2015

A	B	C	D	E	F	G	H	I
Year	**Total Number of Customers** (From Cons. Plan)	**Total Number of Eligible Customers** (From Cons. Plan)	**Projected Cumulative Number of Program Participants** (From Cons. Plan)	**Projected Cumulative Penetration Level %** (D/C X 100)	**Actual Annual Number of Program Participants** (Actual Participants)	**Actual Cumulative Number of Program Participants** (Actual Participants Plan-To-Date)	**Actual Cumulative Penetration Level %** (G/C X 100)	**Actual Participation Over (Under) Projected Participants** (Column G-Column D)
2015	55,525	47,673	...	0.00%	0	0	0.00%	0
2016	55,992	48,140	...	0.00%				
2017	56,539	48,687	...	0.00%				
2018	57,062	49,210	...	0.00%				
2019	57,534	49,682	...	0.00%				
2020	57,975	50,123	...	0.00%				
2021	58,355	50,203	...	0.00%				
2022	58,683	50,831	...	0.00%				
2023	58,992	51,140	...	0.00%				
2024	59,264	51,412	...	0.00%				

Annual Demand and Energy Savings	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	------	------	0	0
Summer kW Reduction	------	------	0	0
Annual kWh Reduction	------	------	0	0

	Annual
Utility Cost per Installation:	N/A
Total Program Cost of the Utility ($000):	$4
Net Benefits of Measures Installed During Reporting Period:	N/A

DSM PROGRAM PROGRESS REPORT
(2015 DSM PLAN)

Utility: Gulf Power Company

Program Name: Commercial/Industrial Custom Incentive

Program Start Date: September, 2015

Reporting Period: Annual 2015 0

	Meter			Generator		
	Summer kW	**Winter kW**	**Energy kWh**	**Summer kW**	**Winter kW**	**Energy kWh**
2015	**0**	**0**	**0**	**0**	**0**	**0**
2016						
2017						
2018						
2019						
Cumulative	0	0	0	0	0	0

Projects - 2015	Meter			Generator		
	Summer kW	**Winter kW**	**Energy kWh**	**Summer kW**	**Winter kW**	**Energy kWh**
Total	0.00	0.00	0	0.00	0.00	0

GULF POWER COMPANY
2015 DSM Progress Report
Savings at the Meter
2015 DSM PLAN

		A	B	C	D	E	F	G	H	I	J
		Total	Per Unit	Per Unit	Per Unit	Total	Total	Total	Cumulative	Cumulative	Cumulative
Residential Programs	**Measures**	**Units**	**Win. kW**	**Sum. kW**	**kWh**	**Win. MW**	**Sum. MW**	**GWh**	**Win. MW**	**Sum. MW**	**GWh**
Community Energy Saver	Residential Community Energy Saver	149	0.11	0.05	769	0.02	0.01	0.11	0.02	0.01	0.11
Landlord/Renter Custom Incentive	Landlord/Renter Customer Incentive Program	0	------	------	------	0.00	0.00	0.00	0.00	0.00	0.00
HVAC Efficiency Improvement	Residential HVAC Maintenance	999	0.07	0.24	607	0.07	0.24	0.61	0.07	0.24	0.61
HVAC Efficiency Improvement	Residential HVAC Quality Installation	0	0.08	0.18	451	0.00	0.00	0.00	0.00	0.00	0.00
HVAC Efficiency Improvement	Residential Duct Repair	0	1.11	0.15	303	0.00	0.00	0.00	0.00	0.00	0.00
High Performance Window	Residential High Performance Window	251	0.24	0.21	391	0.06	0.05	0.10	0.06	0.05	0.10
Reflective Roof	Residential Reflective Roof	60	0.00	0.41	1,029	0.00	0.02	0.06	0.00	0.02	0.06
Energy Select	Energy Select	472	1.07	1.80	735	0.51	0.85	0.35	0.51	0.85	0.35
Self-Install Energy Efficiency	Residential Energy Star Window A/C	1	0.00	0.04	82	0.00	0.00	0.00	0.00	0.00	0.00
		Total Residential Applicable To Goal				**0.66**	**1.17**	**1.23**	**0.66**	**1.17**	**1.23**
Residential Energy Audit and Education	Residential Energy Audit	2,301	------	------	------	-----	-----	-----	-----	-----	-----
				Total Residential		**0.66**	**1.17**	**1.23**	**0.66**	**1.17**	**1.23**
Commercial and Industrial Programs	**Measures**										
Commercial HVAC Retrocommissioning	Commercial HVAC Retrocommissioning	5	0.00	0.30	965	0.00	0.00	0.00	0.00	0.00	0.00
Commercial Building Efficiency	Commercial Geothermal Heat Pump Program	37	0.27	0.29	685	0.01	0.01	0.03	0.01	0.01	0.03
Commercial Building Efficiency	Commercial Ceiling/Roof Insulation Program	20,555	0.00	0.00	1	0.00	0.01	0.02	0.00	0.01	0.02
Commercial Building Efficiency	Commercial Reflective Roof	59,300	0.00	0.00	2	0.00	0.04	0.10	0.00	0.04	0.10
Commercial/Industrial Custom Incentive	Commercial/Industrial Custom Incentive	0	------	------	------	0.00	0.00	0.00	0.00	0.00	0.00
		Total Commercial/Industrial Applicable to Goal				**0.01**	**0.06**	**0.15**	**0.01**	**0.06**	**0.15**
Commercial/Industrial Energy Analysis	Commercial/Industrial Energy Analysis	125	------	------	------	-----	-----	-----	-----	-----	-----
				Total Commercial/Industrial		**0.01**	**0.06**	**0.15**	**0.01**	**0.06**	**0.15**

Column A:	Actual acheived for the reporting year.
Column B:	As filed in the Conservation Plan Filing
Column C:	As filed in the Conservation Plan Filing
Column D:	As filed in the Conservation Plan Filing
Column E:	(Column A) X (Column B)
Column F:	(Column A) X (Column C)
Column G:	(Column A) X (Column D)
Column H:	Annual Results plus any/all previous Annual Results for this conservation plan.
Column I:	Annual Results plus any/all previous Annual Results for this conservation plan.
Column J:	Annual Results plus any/all previous Annual Results for this conservation plan.

GULF POWER COMPANY
2015 DSM Progress Report
Savings at the Generator
2015 DSM PLAN

		A	B	C	D	E	F	G	H	I	J
		Total	Per Unit	Per Unit	Per Unit	Total	Total	Total	Cumulative	Cumulative	Cumulative
Residential Programs	**Measures**	**Units**	**Win. kW**	**Sum. kW**	**kWh**	**Win. MW**	**Sum. MW**	**GWh**	**Win. MW**	**Sum. MW**	**GWh**
Community Energy Saver	Residential Community Energy Saver	149	0.14	0.06	810	0.02	0.01	0.12	0.02	0.01	0.12
Landlord/Renter Custom Incentive	Landlord/Renter Customer Incentive Program	0	------	------	------	0.00	0.00	0.00	0.00	0.00	0.00
HVAC Efficiency Improvement	Residential HVAC Maintenance	999	0.08	0.29	639	0.08	0.29	0.64	0.08	0.29	0.64
HVAC Efficiency Improvement	Residential HVAC Quality Installation	0	0.10	0.22	475	0.00	0.00	0.00	0.00	0.00	0.00
HVAC Efficiency Improvement	Residential Duct Repair	0	1.37	0.18	319	0.00	0.00	0.00	0.00	0.00	0.00
High Performance Window	Residential High Performance Window	251	0.30	0.26	412	0.08	0.07	0.10	0.08	0.07	0.10
Reflective Roof	Residential Reflective Roof	60	0.00	0.50	1,084	0.00	0.03	0.07	0.00	0.03	0.07
Energy Select	Energy Select	472	1.32	2.22	774	0.62	1.05	0.37	0.62	1.05	0.37
Self-Install Energy Efficiency	Residential Energy Star Window A/C	1	0.00	0.05	86	0.00	0.00	0.00	0.00	0.00	0.00
		Total Residential Applicable To Goal				**0.80**	**1.45**	**1.30**	**0.80**	**1.45**	**1.30**
Residential Energy Audit and Education	Residential Energy Audit	2,301	------	------	------	-----	-----	-----	-----	-----	-----
				Total Residential		**0.80**	**1.45**	**1.30**	**0.80**	**1.45**	**1.30**
Commercial and Industrial Programs	**Measures**										
Commercial HVAC Retrocommissioning	Commercial HVAC Retrocommissioning	5	0.00	0.37	1,016	0.00	0.00	0.01	0.00	0.00	0.01
Commercial Building Efficiency	Commercial Geothermal Heat Pump Program	37	0.33	0.36	721	0.01	0.01	0.03	0.01	0.01	0.03
Commercial Building Efficiency	Commercial Ceiling/Roof Insulation Program	20,555	0.00	0.00	1	0.00	0.01	0.02	0.00	0.01	0.02
Commercial Building Efficiency	Commercial Reflective Roof	59,300	0.00	0.00	2	0.00	0.05	0.11	0.00	0.05	0.11
Commercial/Industrial Custom Incentive	Commercial/Industrial Custom Incentive	0	------	------	------	0.00	0.00	0.00	0.00	0.00	0.00
		Total Commercial/Industrial Applicable to Goal				**0.01**	**0.07**	**0.17**	**0.01**	**0.07**	**0.17**
Commercial/Industrial Energy Analysis	Commercial/Industrial Energy Analysis	125	------	------	------	-----	-----	-----	-----	-----	-----
				Total Commercial/Industrial		**0.01**	**0.07**	**0.17**	**0.01**	**0.07**	**0.17**

Column A:	Actual acheived for the reporting year.
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Column J:	Annual Results plus any/all previous Annual Results for this conservation plan.

Comparison of Achieved kW and kWh Reductions
With Public Service Commission Established Goals
at the Generator
2010-2015 DSM PLAN COMBINED

Utility: GULF POWER COMPANY

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
	Total Achieved	Com. Appr. Goal	% Variance	Total Achieved	Com. Appr. Goal	% Variance	Total Achieved	Com. Appr. Goal	% Variance
2015	12.69	1.3	876%	12.97	2.3	464%	34.16	2.3	1385%
2016		1.8			3.2			3.2	
2017		2.3			4.1			4.2	
2018		2.9			5.0			5.1	
2019		3.4			5.9			6.0	
2020		3.8			6.7			6.8	
2021		4.3			7.5			7.6	
2022		4.6			8.1			8.3	
2023		5.0			8.8			8.9	
2024		5.3			9.3			9.5	

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
	Total Achieved	Com. Appr. Goal	% Variance	Total Achieved	Com. Appr. Goal	% Variance	Total Achieved	Com. Appr. Goal	% Variance
2015	4.24	0.1	4140%	6.38	0.3	2027%	13.77	0.8	1621%
2016		0.1			0.4			1.2	
2017		0.1			0.5			1.5	
2018		0.2			0.6			1.8	
2019		0.2			0.7			2.2	
2020		0.2			0.8			2.5	
2021		0.2			0.9			2.7	
2022		0.3			0.9			3.0	
2023		0.3			1.0			3.2	
2024		0.3			1.1			3.4	

Total Company (including Solar)

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
	Total Achieved	Com. Appr. Goal	% Variance	Total Achieved	Com. Appr. Goal	% Variance	Total Achieved	Com. Appr. Goal	% Variance
2015	17.04	1.4	1117%	19.57	2.6	653%	48.33	3.1	1459%
2016		1.9			3.6			4.4	
2017		2.4			4.6			5.7	
2018		3.1			5.6			6.9	
2019		3.6			6.6			8.2	
2020		4.0			7.5			9.3	
2021		4.5			8.4			10.3	
2022		4.9			9.0			11.3	
2023		5.3			9.8			12.1	
2024		5.6			10.4			12.9	

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy and correct copy of the foregoing was served on this 13th day of January, 2017, via electronic mail on:

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/s/ Bradley Marshall
Bradley Marshall, Attorney