BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Gulf Power Company	Docket No. 160186
In re: Petition for approval of 2016 depreciation and dismantlement studies, approval of proposed depreciation rates and annual dismantlement accruals and Plant Smith Units 1 and 2 regulatory asset amortization, by Gulf Power Company	Docket No. 160170 Filed: January 13, 2017

Prepared Direct Testimony of Jeffrey M. Loiter

On Behalf of
Sierra Club

January 13, 2017

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Exhibit JML -11 National Consumer Law Center, *Utility Rate Design: How Mandatory Monthly Customer Fees Cause Disproportionate Harm* (2015) (prepared using data sourced from the U.S. Energy Information Administration's Residential Energy Consumption Survey, 2009).

Exhibit JML -12 Minnesota Public Utilities Commission, *Findings of Fact, Conclusions, and Order*, issued May 8, 2015, in Docket No. E-002/GR 13-868, In re: Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, p. 88.

Exhibit JML -13 United States Department of Agriculture*, Characteristics of Supplemental Nutrition Assistance Program Households: Fiscal Year 2014,* Report No. SNAP-15-CHAR (Dec. 2015).

Exhibit JML -14 United States Department of Agriculture, *Supplemental Nutrition Assistance Program FY 2016 Income Eligibility Standards* (Updated Sept 24, 2015).

Exhibit JML -15 Florida Public Service Commission, *2016 Facts & Figures of the Florida Utility Industry*, p. 5 (April 2016).

Already on the record:

Blank, L, and D. Gegax, *An enhanced two-part tariff methodology when demand charges are not used*, *Electricity Journal.* Vol. 29, Issue 3, p. 42-47.

I. IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and address.

A. Jeffrey M. Loiter, Optimal Energy, Inc., 10600 Route 116, Hinesburg, VT 05461.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Sierra Club.

Q. By whom are you employed and in what capacity?

A. I am a Partner in Optimal Energy, Inc., a consultancy specializing in energy efficiency and utility planning. In this capacity, I direct and perform analyses, author reports and presentations, manage staff, and interact with clients to serve their consulting needs.

Q. Have you testified before the Florida Public Service Comission?

A. No.

Q. Please provide a summary of your qualifications and experience.

A. I have 20 years of consulting experience in environmental policy, energy, and natural resource issues. For the past 10 years, I have been engaged in a variety of work at Optimal Energy related to energy efficiency, electric utility policy, integrated resource planning, and related topics. For example, I advise clients on energy efficiency program design and implementation. I have assisted with the design and development of statewide and utility-specific efficiency programs in Maine, Maryland, New York, Massachusetts, and Tennessee. I currently support program implementation and on-going efficiency program design and development for Orange and Rockland Utilities in New York and the Connecticut Municipal Electric Energy Cooperative. In addition, I provide planning and analysis services in support of three bodies that have the responsibility of overseeing energy efficiency planning, design, implementation, and evaluation in their respective states: the Massachusetts Energy Efficiency Advisory Council, the Rhode Island Energy Efficiency Resource Management Council, and the Delaware Energy Efficiency Advisory Council. I have submitted written testimony to or testified before public utility commissions in Arkansas, Kansas, Kentucky, Maryland, Ohio, Virginia, and West Virginia on topics such as demand-side management, integrated resource planning, and efficiency as a resource in state energy plans.

Prior to joining Optimal Energy in 2006, I was a Senior Associate at Industrial Economics, Inc. in Cambridge, Massachusetts, where I supported state, federal, and international governmental clients with analysis on topics of environmental policy and natural resources damages. I have a B.S. with distinction in Civil and Environmental Engineering from Cornell University and an M.S. in Technology and Policy from the Massachusetts Institute of Technology. My resume is attached as Exhibit JML-1.

II. INTRODUCTION AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses Gulf Power Company's ("Gulf" or the "Company") Petition for approval of 2016 depreciation and dismantlement studies, approval of proposed depreciation rates and annual dismantlement accruals, and Plant Smith Units 1 and 2 regulatory asset amortization. Specifically, I address Gulf's proposal to increase its residential fixed charges.

Q. What are your overall conclusions?

A. My analysis shows that Gulf's proposed rate restructure is unfair, unjust, and unreasonable. Contrary to the Company's assertion, the proposed residential rates do not recover demand-related costs more appropriately than do current rates. In fact, the proposed rates will harm low-usage, low-income, and fixed-income customers, and deprive all residential customers of control over their monthly bill.

Q. What sources have you relied on in your assessment of Gulf's proposal to increase residential fixed charges?

A. I have focused on Gulf's filings related to changes in residential rates and in particular the proposal to increase fixed charges, including its petition, direct testimony and exhibits. I have also drawn on several recent publications, government publications, and state electric utility regulatory proceedings pertaining to residential rates and related topics. I have referenced the sources relied upon in my testimony and/or attached these sources as exhibits.

III. Findings and Recommendations

Q. Please summarize your findings in this case.

A. My findings are as follows:

1. A residential customer's individual maximum demand is not an appropriate measure of the costs they cause to the Company.
2. Demand charges for residential customers are accompanied by several drawbacks, including a lack of understanding, information, and control on the part of the customer.
3. Increased fixed charges for residential customers are also accompanied by significant drawbacks, including encouraging greater energy consumption, discouraging energy efficiency, and penalizing previous investments in efficiency.
4. Increased fixed charges for residential customers reduce customer control over their energy costs.
5. Increased fixed charges for residential customers disproportionately harm low-usage customers, who are more likely to be low-income and fixed-income consumers.
6. The Company's proposed program to assist low-income customers is unlikely to adequately reach customers who will be harmed by increased fixed charges.
7. The Company's methodology for determining the proposed fixed charge is untested, has never been applied in any previous rate-making proceeding, and begins with an incorrect assumption regarding the alignment of rates and

costs, namely, that a customer's individual maximum demand is a reasonable representation of their cost causation.

Q. What are your recommendations to this Commission?

A. Based on my findings, I recommend that the Commission reject the Company's proposed changes to its residential rates.

IV. GULF'S CURRENT RESIDENTIAL RATE STRUCTURE

Q: Before we discuss Gulf's proposed changes, please describe the Company's current rate structure.

A: Gulf currently offers its non-lighting residential customers four rate options. The Company's standard default rate, the Residential Service ("RS") rate, is a two-part fixed-variable rate made up of a fixed base charge (assessed on a per day basis) to cover fixed costs associated with serving each customer and a variable energy charge assessed on each unit of energy (kWh) consumed. Ninety-two percent of Gulf's non-lighting residential customers are on this rate. Gulf also offers two optional time-of-use rates with variable energy charges based on the time of day. Gulf's Residential Service Variable Pricing ("RSVP") rate, which about 4% of its residential customers have opted into, divides the energy charge into low, medium, high, and critical tiers. Gulf's Residential Service Time-of-Use ("RSTOU") rate divides the energy charge into on- and off-peak tiers with a critical peak credit. However the RSTOU rate is part of a pilot program, which is limited to about 400 customers and is currently full. Finally, Gulf customers can also opt into the Company's FlatBill program whereby

Gulf and the customer negotiate an annual contract that is then divided into twelve equal monthly payments. McGee (Pages 3-4).

V. Overview of Gulf's Proposal to Increase Fixed Charges

Q: What changes does the Company propose to current residential rates?

A: With the exception of Flatbill, Gulf is proposing a large increase to the fixed base charge in the company's current residential rates (that is, the RS, RSPV, and RSTOU rates) of nearly 150%, from \$0.62 per day to \$1.58 per day. At the same time, the rate for the variable portion of the customer's bill would be decreased from roughly 4.6 cents/kWh to 3.3 cents/kWh.

Q: What reasoning does the Company give for making this rate change?

A: The Company claims this improves both equity and customers' experience with Gulf's product by recovering demand-related costs more appropriately than current rates. The Company generally categorizes its costs as one of three types: customer-related, demand-related, and energy-related. Company Witness O'Sheasy defines these costs as follows: "(1) customer-related, which are costs that vary with the number of customers or the fact that customers must be able to receive service; (2) energy-related, which pertain to costs that vary with energy consumption (kWh); and (3) demand-related, which are costs that are incurred to serve peak needs for electricity (kW)." O'Sheasy (Page 8, lines 19-23).

The current rate structure collects all residential demand-related costs through the energy charge. Therefore, the proposed change does not mean that the Company's fixed costs of serving each customer have increased nearly three-fold, but that the Company is shifting recovery of demand-related charges into fixed charges. The Company asserts that it is better to collect a larger portion of demand-related costs from something other than the energy charge and has proposed to do so largely through the fixed charge.

Q: How did the Company develop these rates/convert demand-related costs to a fixed charge, which is not dependent on a customer's demand?

A: The Company uses a methodology develop by Drs. Larry Blank and Doug Gegax ("Blank & Gegax," or "B&G") of the Center for Public Utilities, a branch of the College of Business at New Mexico State University that is sponsored by over a dozen utility companies and industry groups, including Southern Company.[1] Briefly, this method seeks to emulate a rate consisting of all three cost components using only the fixed charge and the energy charge. It does so by developing a linear regression from a set of customer bills under a hypothetical three-part rate as a function of energy consumption. This function will indicate a non-zero bill for zero energy consumption, which is taken to be the appropriate fixed charge to serve as a proxy for the average customer demand charge. Because the result of the analysis is based on a linear regression, it is most accurate for customers whose demand relative to consumption is near the average. For those with relatively greater or lesser demand for a given level of consumption, it will over or under-estimate their costs as assessed under a three-part rate.

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[1] *CPU Sponsors*, New Mexico State University, goo.gl/4GcVvw (last visited Jan.12, 2017). Exhibit JML-2.

Q: Is the Company proposing any new residential rates that recover demand-related costs based on a customer's actual demand?

A: Yes, the Company is proposing two new optional three-part residential rates. The Demand ("RSD") rate would include a fixed base charge, a variable energy charge, and a variable demand change based the customer's maximum demand (measured in kW) during the month. The Demand Time of-Use Conservation ("RSDT") rate divides the demand portion of the bill into two parts, one for the customer's maximum demand during the month and one for their maximum demand during defined on-peak hours. These new rates will have lower fixed base charges than the other residential rates. McGee (Pages 10-11).

Q: Is the Company proposing any other changes to residential rates?

A: Yes, the Company is also proposing a new rate rider for low-income customers called the Customer Assistance Program (CAP). Qualifying customers will receive a bill credit of $0.69 per day. Company Witness McGee presents information that asserts that this will offset all of the increase these customers would have otherwise incurred under the new rate structure, even for very-low use customers. McGee (Schedule 7). However, even if the customer's bill would be equal with the rider, the fixed portion of the bill would still increase by $6.60. Furthermore, as I explain below this rider does not go far enough to protect vulnerable ratepayers.

Q: Do you agree with the Company's reasoning behind the proposed rate structure changes?

A: No. Gulf's proposal is a premature and unsubstantiated rate design change.

The Company's proposal is predicated on two assertions. First, that a customer's individual demand is a reasonable measure of the demand-related costs they cause to the Company, and second, that demand-related costs can be appropriately and accurately recovered through the fixed charge. Neither of these assertions are supported by the evidence. Furthermore, the Company has not adequately recognized the potential disadvantages and negative outcomes for customers of either true demand rates or increased fixed charges.

VI. Residential Demand Charges Have Many Disadvantages and May Not Reflect Cost-Causation

Q: Is the Company's proposed rate structure based on the assumption that a three-part rate that includes a demand charge is a more accurate reflection of cost causation and therefore a more equitable rate for its customers?

A: Yes. Witness McGee states that a three-part demand rate "best aligns with costs." McGee (Page 9, lines 6-9).

Q: But the Company is not proposing a three-part rate for its residential customers, except as an optional rate that customers can choose on their own. Do they give any reasons for this?

A: Yes. The primary reason they cite is that mandatory three-part rates are met with "limited customer acceptance." McGee (Page 9, lines 15-16). According to Witness McGee "Demand rates…introduce a new concept called demand…,another measurement…, another rate component…, and another line item on the customer's bill." McGee (Page 10, lines 6-9).

Q: Do you agree these rates will likely be met with limited customer acceptance?

A: Yes, and given the steep learning curve and several other important problems with demand rates for residential customers, I would say that limited customer acceptance is an understatement. Even if they were implemented in a way that accurately reflects customers' cost causation (which is far from a given, as I will explain later), a reasonable and successful demand charge also requires that customers must be able to know their total demand at all times, know what equipment and behavior contributes to that demand, and have the ability to modify behavior and equipment to control their demand. Currently, the vast majority of residential customers are incapable of any of these.

Q: Do residential customers typically know what their total or maximum demand is?

A: No, and Gulf has not indicated that residential customers have *any* information on their maximum demand, let alone access to the real-time demand information necessary to allow them to respond to demand charges.

Q: Has the company indicated how they will measure maximum demand for their optional demand rates?

A: Yes. Maximum demand will be measured on an hourly basis (i.e. the customer's demand charge will be based on her highest average hour of demand, as well as her highest average hour of demand during peak hours under the RSDT rate). Evans (Page 8, lines 2-15).

Q: Assuming customers have a means of knowing their maximum demand and how it is measured and determined, how can they understand what contributes to their demand?

A: Because a customer's demand is composed of the individual demand of dozens or even hundreds of individual pieces of equipment and plug loads, understanding one's demand potentially means understanding the demand for every one of these items. Realistically, maximum demand is driven by a handful of relatively obvious appliances (e.g., electric hot water heaters, electric ranges, heat pumps and air conditioners, etc.) and some that may not be so obvious to the consumer (e.g., hair dryer, coffee pot, refrigerator). Understanding these sources and how they interact requires the customer to know both the potential maximum demand of each item and the likely timing of that demand. While there are some sophisticated home energy management systems available, they are expensive and installed in a de minimis number of homes. Practically, residential consumers have no way of gathering this information at this time.

Q: If customers could develop an understanding of what contributes to their maximum demand, what options are available for them to control this demand and therefore control demand charges?

A: As I just noted, home energy management systems are rare. Therefore, monitoring and controlling demand by controlling equipment operation cycles is difficult at best.

Customers could put high-use equipment on a timer, but that is only useful in the case of pre-determined peak hours, which is not the case with the proposed RSD rate or the maximum demand portion of the proposed RSDT rate. Even customers who wish to control their bills by controlling demand would have a very difficult time doing so. More importantly, assessing demand charges based on a customer's own individual maximum demand does not accurately reflect their cost-causation.

Q: Can you please expand on that?

A: Absolutely. Investments in demand-related infrastructure are based on the largest aggregate demand served by that equipment, that is, the peak load on the system or that portion of the system. But residential consumers have much more diversity in their usage, with individual customer maximum demands seldom coinciding with the system peak.[2] Because 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 with when other customers sharing the same infrastructure are experiencing their maximum demands.[3] As a result, demand charges are unable to account for the diverse usage patterns of residential and small commercial customers, often do not coincide with peak system demand, and can result in significant and inequitable cost-shifting.[4]

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[2] *See* Lazar, J., *Use Great Caution in Design of Residential Demand Charges, Natural Gas & Electricity*, Vol. 32, Issue 7, p. 13-19 (Feb. 2016), Exhibit JML-3.
[3] *See* Whited, M. et al, *Caught in a Fix: The Problem with Fixed Charges for Electricity*, Prepared for Consumers Union by Synapse Energy Economics, p. 39 (February 9, 2016), Exhibit JML-4.
[4] Southern Environmental Law Center, *A Troubling Trend in Rate Design: Proposed Rate Design Alternatives to Harmful Fixed Charges* (Dec. 2015), Exhibit JML-5.

VII. Increased Fixed Charges Are Also Problematic and Are Not a Reasonable Means of Recovering Demand-Related Costs

Q: What are the potential disadvantages associated with increasing the fixed charge of the bill?

A: There are several. Increased fixed charges encourage greater energy consumption as a result of decreased marginal cost of energy; discourage energy efficiency and penalize previous investments in efficiency; reduce customer control over their energy costs; and disproportionately harm low-usage, low-income, and fixed-income customers.

Q: Please explain how increased fixed charges encourage greater energy consumption.

A: As the Company has explained, the increase in the fixed charge is offset by a decrease in the variable energy charge. Basic economics tells us that as the price of a good or service decreases, the demand for that good or service increases. The extent to which this occurs for any item is called price elasticity, the change in consumption of a good or service resulting from a change in pricing. As with most goods, the elasticity of consumption for electricity is negative, meaning that as prices increase, consumption decreases, and vice versa. Therefore, the lower unit cost of energy proposed by the Company will result in an increase in consumption.

Q: How large might this effect be for the Company's residential customers?

A: I cannot say with any certainty, but I can provide some information that will indicate the potential range of effect. First, I calculate that the variable portion of the basic residential rate decreases by 17.5%, according to the data presented in McGee Schedule 1. Next, we need an estimate for the price elasticity of electricity consumption, which is relatively inelastic, meaning that for a 1% decrease in price, we would expect a lower than 1% increase in consumption. Using a conservative estimate of -0.1,[5] a 17.5% decrease in price would be expected to result in a 1.7% increase in consumption. This is a significant increase, equal to about one and a half years of the Company's projected load growth.

Q: You also mentioned that increased fixed charges would discourage energy efficiency. Can you please explain the reasoning behind that statement?

A: Increased fixed charges provide a disincentive for customers to invest in energy efficiency measures or on-site generation such as solar PV systems. Because less of their bill is tied to their usage, the connection between reducing consumption and reducing bills is weakened. This lower return on investment would surely reduce the number of customers investing in efficiency and renewables and the size of those investments. Increased fixed charges particularly hurt those who have already invested in these resources, as the return on their investment comes from the reduction in their energy costs each year. Shifting costs away from the variable charge and into the fixed charge will reduce this stream of benefits. For example, for

[5] *See* Ros, A. J., *An Econometric Assessment of Electricity Demand in the United States using Panel Data and the Impact of Retail Competition on Prices*, NERA Economic Consulting (June 9, 2015), *available at* goo.gl/xPRcyl, Exhibit JML-6; Paul, A. et al, *A Partial Adjustment Model of U.S. Electricity Demand by Region, Season, and Sector, Resources for the Future Discussion Paper*, RFF DP 08-50 (April 2009), *available at* goo.gl/uYwEH9, Exhibit JML-7.

an efficiency investment with a simple payback of 10 years, the proposed reduction in the variable energy charge will extend this to 12 years. Gulf's customers will have no recourse for this change. Given that the Company invested over $6 million in residential DSM programs between 2010 and 2015, there are likely to be millions of dollars of existing efficiency investments made by Gulf's residential customers, which would become a greater financial burden.[6]

Q: Have other commissions addressed the problem of increased fixed charges discouraging energy efficiency?

A: Absolutely. The Washington Utilities and Transportation Commission cited this concern when it denied a 2015 request to increase fixed charges, stating, "Including distribution costs in the basic charge and increasing it 81%, as the Company proposes in this case, does not promote, and may be antithetical to, the realization of conservation goals."[7]

Q: You also stated that increased fixed charges reduce customer control. How so?

A: Although technology increasingly empowers customers to understand and manage their energy use, customers must pay fixed charges regardless of usage. Increased fixed charges leave a smaller portion of the bill that customers can control by reducing their energy use. This problem was cited by the Missouri Public Service Commission to reject Ameren's request to increase its residential customer charge.

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[6] Data for residential DSM program spending sourced from McGee, R., *Gulf Power Company's 2015 Annual FEECA Program Progress Report* (March 1, 2016), Exhibit JML-8.

[7] Washington Utilities and Transportation Commission, *Order 08 Final Order Rejecting Tariff Sheets, Resolving Contested Issues, Authorizing And Requiring Compliance Filings*, issued March 25, 2015 in Dockets UE-140762, UE-140617, UE-131384 and UE-140094, p. 91, Exhibit JML-9.

The Commission stated, "There are strong public policy considerations in favor of not increasing the [fixed] 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."[8]

Q: Does the Company offer any solution to this?

A: Not to my satisfaction, no. With respect to providing customers with more control over their bill, Gulf states that customers can do so by opting-in to the proposed three-part rates with demand charges. This is inappropriate; customers should have control of their bills by default, not solely because they choose to participate in an optional rate. Few customers are likely to do so, for several reasons. First, only 4% of Gulf's residential customers take service under the RSVP time-of-use rate with critical peak pricing. Presumably, more than 4% of their customers are interested in controlling their electric bill, yet do not select a more complicated rate as a means of doing so. Second, as I explain above, demand charges represent an entirely new concept for nearly every residential customer that will require great additional effort to understand. I would expect even fewer customers to select an optional demand rate than have selected the existing time-of-use rate. Finally, as previously discussed, even assuming customers choose Gulf's proposed optional demand rates and understand them perfectly, because those customers have no way of accessing critical demand

[8] Missouri Public Service Commission, *Report and Order*, issued April 29, 2015 in Case No. ER-2014-0258, In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Revenues for Electric Service, p. 76-77, Exhibit JML-10.

data, they have very little ability to actually respond to any sort of demand price signal. In short, despite Gulf's claim that it is providing customers with more options to control their bill, the rate restructure proposal set forth here only serves to undermine customer control.

Q: How are low-income and low-usage customers affected by higher fixed charges?

A. Low-usage customers will be the most negatively affected by higher fixed charges. Their increased bills will compensate for the reduced bills of high usage customers. Gulf asserts that income and energy usage (kWh) are not necessarily correlated (McGee, p. 18) but presents no data or information to support that contention. Instead, it offers unsupported anecdotal examples intended to demonstrate that they may be INVERSELY correlated, noting that high energy users are those with "older inefficient manufactured homes and poorly-insulated homes" (implying that these customers would typically be low income) while low energy users are "condo owners, vacation home owners, and boat dock owners," (implying that these customers would typically be higher income). This type of anecdotal information fails to accurately reflect the typical situation for most customers. In fact, low usage customers are likely to be customers with lower incomes who can least afford to see increases on their electric bills.

Research by the National Consumer Law Center found this to be true throughout the U.S. generally, with Florida no exception. They found that households with annual income less than $25,000 use 13% less electricity on average than those with annual incomes between $25,000 and $50,000, nearly 30% less than households earning between $50,000 and $75,000 per year, 35% less than households earning between $75,000 and $100,000, and 44% less – barely more than half – than households earning over $100,000. Older consumers, who are more likely to be on a fixed income, are also typically lower users, with consumers over 65 using 24% less electricity on average than those under 65.[9] Lower-income and elder-headed households clearly use less electricity than their counterparts, and as a result, utility proposals to increase fixed charges while lowering the variable energy charge penalize low-volume consumers and disproportionately harm these groups of ratepayers.

The Minnesota Public Utilities recognized these problems in their recent ruling against Xcel's proposal to increase the fixed charge for residential customers by 15% (as compared to nearly 150%, as proposed by Gulf). In its reasoning, the Commission indicated 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."[10]

Q: But doesn't the Company also propose a program by which low-income customers can receive a lower rate and therefore a lower total energy bill?

[9] National Consumer Law Center, *Utility Rate Design: How Mandatory Monthly Customer Fees Cause Disproportionate Harm* (2015) (prepared using data sourced from the U.S. Energy Information Administration's Residential Energy Consumption Survey, 2009), Exhibit JML-11.
[10] Minnesota Public Utilities Commission, *Findings of Fact, Conclusions, and Order*, issued May 8, 2015, in Docket No. E-002/GR 13-868, In re: Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, p. 88, Exhibit JML-12.

A: Yes, but the proposed criterion for participating will not necessarily protect all low-income or otherwise vulnerable customers for whom an increased electric bill would be a burden. The proposed rider is only available to customers of record who are participants in the Supplemental Nutrition Assistance Program ("SNAP"), excluding many customers who are likely to be harmed by these rate changes. McGee (Page 17, lines 2-5). Elderly customers, for instance, who often live on fixed incomes tend to live in smaller households[11] and therefore are only eligible for SNAP at lower income levels.[12] While they may not qualify for SNAP, these customers have little discretion or ability to absorb a higher fixed energy cost burden that is beyond their control. The company estimates that roughly 10% of its customers will be eligible for the low-income credit, but the very nature of the proposed rate change suggests that roughly half of customers will get a bill increase and half will get a bill decrease. There will clearly be customers who will not be eligible for low-income assistance but for whom the unavoidable bill increase will represent a hardship.

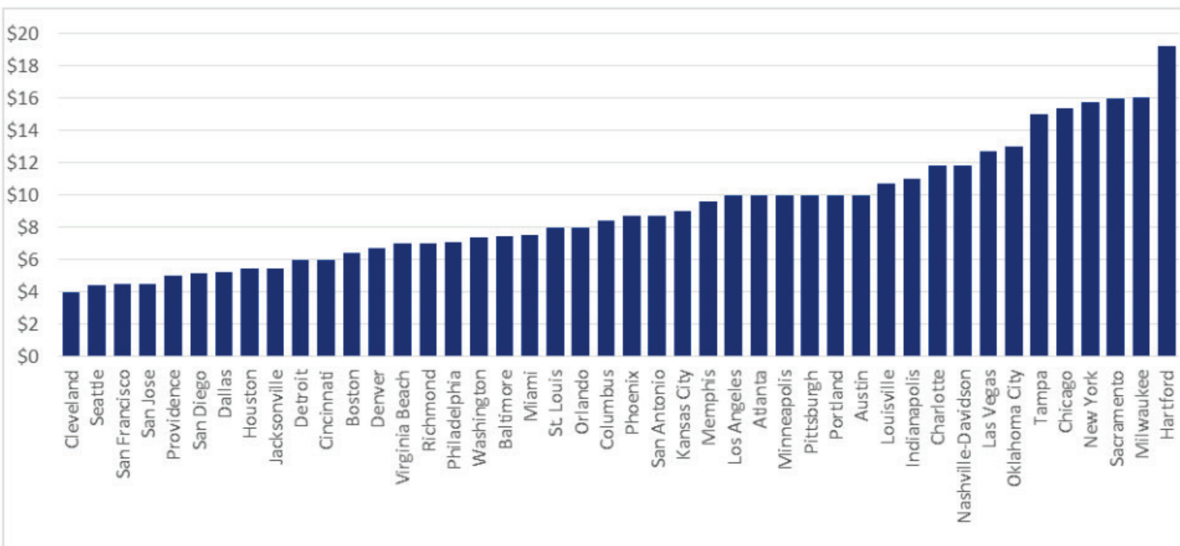
Q: How does Gulf's proposed fixed charge compare to those of other electric utilities?

A. The fixed charge proposed by Gulf is astronomical compared to the fixed charges of most other utilities. Gulf proposes to nearly triple its fixed charges, resulting in a fixed charge increase from about $18.60 per month to about $47.50 per month. A recent report surveying similar requests for increases in fixed charges demonstrates

[11] United States Department of Agriculture, *Characteristics of Supplemental Nutrition Assistance Program Households: Fiscal Year 2014,* Report No. SNAP-15-CHAR (Dec. 2015), Exhibit JML-13.
[12] United States Department of Agriculture, *Supplemental Nutrition Assistance Program FY 2016 Income Eligibility Standards* (Updated Sept 24, 2015), Exhibit JML-14.

just how exceptional such a large increase is. If approved, this fixed charge would be among the highest in the country and far higher than those paid by the vast majority of electric consumers in the United States. The figure below, taken from the Consumers Union report, shows that the proposed fixed charge would be more than double the highest such charge in most major cities.[13] Furthermore, at the existing fixed charge of $18.60 per month, Gulf Power already charges residential customers a higher fixed charge than any other investor-owned electric utility in Florida.[14]

FIGURE 1: MONTHLY FIXED CHARGES IN MAJOR CITIES



Source: Utility tariff sheets for residential service as of August 19, 2015.

Not only is Gulf's proposed fixed charge out of scale with existing fixed charges at other utilities, the Consumers Union report shows that the requested increase is also greater than any similar proposals pending at the time of the report.[15]

[13] Whited, *supra* note 3, at Figure 2.
[14] Florida Public Service Commission, *2016 Facts & Figures of the Florida Utility Industry*, p. 5, Exhibit JML-15.
[15] Whited, *supra* note 3, at Figure 4.

Q: You have provided a lot of information on both demand charges and increased fixed charges for residential ratepayers. Can you please summarize your position on these topics as it related to Gulf's proposal?

A. Certainly. First, the Company asserts that demand charges for residential customers more accurately and fairly recover demand-related costs, but fails to recognize that a simple measurement of maximum individual demand does not in fact accurately reflect demand-related costs and that demand charges present several disadvantages for customers. Second, the Company asserts that using greater fixed charges is a reasonable substitute for demand charges, but fails to recognize the disadvantages of this strategy.

VIII. THE COMPANY'S METHODOLOGY FOR DEVELOPING THE FIXED CHARGE IS UNTESTED

Q: Leaving your objections aside for the moment, we have not discussed the Company's methodology for converting demand charges into a proxy fixed charge. Do you have any comment on their approach?

A: Yes, I do. The proposed Blank and Gegax methodology is a new concept that has only recently been published.[16] To my knowledge, it has never been applied in any rate-making proceeding, nor have the Company's witness provided any evidence that it has been supported, critiqued, or otherwise commented on by any regulatory body or peer-reviewed publication. Furthermore, it begins with the assumption that a three-part rate that includes a demand charge is "best" because it appropriately aligns rates

[16] Blank, L, and D. Gegax, *An enhanced two-part tariff methodology when demand charges are not used*, *Electricity Journal.* Vol. 29, Issue 3, p. 42-47 (April 2016).

with costs. McGee (Page 9, lines 6-9). Yet this suffers from the problems I have already noted, primarily that to the extent the methodology uses data on customers' individual maximum demand rather than their contribution to peak demand (and therefore, demand-related costs), it is already an inaccurate representation of a cost-based rate structure.

Q: **Does this conclude your testimony?**

A: Yes.

JEFFREY M. LOITER, PARTNER

Optimal Energy|10600 Route 116, Suite 3|Hinesburg, VT 05401|802-482-5610|loiter@optenergy.com

PROFESSIONAL EXPERIENCE

Optimal Energy, Hinesburg, VT. *Partner*, 2015-present; *Managing Consultant*, 2006-2014.

As a Partner, Mr. Loiter is responsible for business development, administrative systems, and staff development in addition to project management. In addition, he provides quality control and editing for all of Optimal's client deliverables. His project work includes designing and developing statewide and utility-specific efficiency programs and supporting program implementation for both public and private-sector clients. He works primarily in the commercial sector on programs targeting electric, natural gas, and un-regulated fossil fuel consumption and specializes in developing solutions that fit the needs of specific customer segments and markets. Mr. Loiter is also an experienced analyst and uses these skills in a variety of contexts, such as reviewing and critiquing utility Integrated Resource Plans and efficiency potential studies.

Independent Consultant, Cambridge, MA, 2005-2006.

As an independent consultant for the Massachusetts Renewable Energy Trust SEED Initiative, Mr. Loiter evaluated renewable energy technology companies' applications for early-stage funding. Responsibilities included leading due diligence efforts on three applications and contributing to several others. Awards recommended for approval totaled $1.4 million. For a separate client, prepared two articles describing the potential impact of proposed federal legislation to increase domestic oil refining capacity, published in Petroleum Technology Quarterly (1Q 2006) and BCC Research/Energy Magazine (2006).

Industrial Economics, Inc., Cambridge, MA. *Associate*, 1997-2000; *Senior Associate*, 2001-2004.

Managed multi-disciplinary qualitative and quantitative assessments of natural resource damages and environmental policy for clients such as NOAA, USFWS, USEPA, USDOJ, the National Park Service, the State of Indiana, and the United Nations.

URS Consultants, Inc., New Orleans & Boston., 1991-1995.

Prepared water, air, and solid and hazardous waste permit applications for state and federal agencies on behalf of industry clients.

EDUCATION

Massachusetts Institute of Technology, Cambridge, MA
Master of Science in Technology & Policy, 1997

Cornell University, Ithaca, NY
Bachelor of Science with distinction, Civil and Environmental Engineering, 1991

REPRESENTATIVE PROJECT EXPERIENCE

Delaware Department of Natural Resources and Environmental Control, Energy Efficiency Advisory Council Program Development and Support (2015-present)
Optimal Energy provides broad program planning, analysis, and strategic guidance to the Delaware Energy Efficiency Advisory Council as it begins developing a new model for joint utility and public-sector delivery of energy efficiency services, with the objective of dramatically increasing energy savings and demand reductions in that state. In support of the Council, Mr. Loiter drafted Council organizing documents and regulations specifying evaluation, measurement, and verification (EM&V) procedures and standards. He also provided the Council with proposed electric and gas energy savings targets as supported by an earlier potential study.

EPA State and Local Branch, EPA National Action Plan for Energy Efficiency (2008)
Prepared two documents for inclusion with EPA's National Action Plan for Energy Efficiency: a guidebook on conducting efficiency potential studies and a handbook describing the funding and administration of clean energy funds.

Connecticut Municipal Electric Energy Cooperative, Conservation and Load Management Consulting (2006-present)
Optimal has provided energy efficiency consulting services to the Connecticut Municipal Electric Energy Cooperative (CMEEC) since the inception of their conservation and load management programs. Mr. Loiter contributes to the full range of these services, including program planning, program savings analysis and reporting, developing incentive and delivery strategies, and managing CMEEC's participation in the ISO-NE Forward Capacity Market. The latter has included drafting M&V plans specifying procedures for meeting all ISO-specified M&V rules and developing a web-based data tracking and reporting system. Mr. Loiter also helps CMEEC develop strategy for and manage participation in new FCM auctions and arranges for required annual certification reviews.

Orange and Rockland Utilities, Energy Efficiency Program Consulting (2006-present)
Optimal Energy supports program implementation and on-going program design and development for Orange and Rockland Utilities, a subsidiary of Consolidated Edison, Inc. Mr. Loiter managed the preparation of a DSM plan and Commission filings for this client during the initial phases of the New York State Energy Efficiency Resource Standard. Prior to that, he led the commercial sector component of an electric and gas potential study for the utility, which included on-site customer audits and residential surveys.

New York State Department of Public Service, Generic Environmental Impact Statement and Supplement (2014-2016)
As part of proceedings on Reforming the Energy Vision (REV) and the Clean Energy Fund (CEF), Optimal contributed to a Generic Environmental Impact Statement (GEIS) by describing alternative energy supply resources, the potential scale of their use under two future scenarios, and the magnitude of possible negative environmental impacts that would result. Mr. Loiter led a team researching several technologies, including energy efficiency, customer-sited renewables, combined heat and power, alternative rate structures, and energy storage. The research led to estimates of the potential scale and impact of these solutions to New York's future energy challenges.

British Columbia Utility Commission, DSM Filing Technical Support (2012-2013)
In support of staff of the BCUC, Optimal Energy reviewed three utility filings related to DSM programs,

cost-recovery, and performance-based ratemaking. Mr. Loiter led a team that reviewed the filings, drafted interrogatories, and provided information regarding the appropriateness of program designs, measure-level costs and savings estimates, and cost-effectiveness inputs such as discount rates and avoided costs.

Maryland Energy Administration, EmPOWER Maryland Filing Reviews (2008-2009)
As part of efforts to reduce per-capita electric and natural gas under the 2008 EmPOWER Maryland Energy Efficiency Act, the Maryland Energy Administration was responsible for reviewing and commenting on utility-delivered energy efficiency programs and for designing and implementing its own state-wide efficiency portfolio. Mr. Loiter contributed to both of these efforts, appearing before the Public Service Commission on two occasions.

REPRESENTATIVE PUBLICATIONS

“Collaboration that Counts: The Role of State Energy Efficiency Stakeholder Councils,” (with D. Sosland, M. Guerard, and J. Schlegel), *2012 ACEEE Summer Study on Energy Efficiency in Buildings,* Pacific Grove, CA, August 2012.

“Persistence and Cost of Behavioral Programs,” presented at National Association of State Utility Consumer Advocates Mid-Year Meeting, Charleston, SC, June 2012.

“Impending EISA Lighting Standards: Impacts on Consumers and Energy Efficiency Lighting Programs,” presented at National Association of Regulatory Utility Commissioners Annual Meeting (with M. DiMascio), Atlanta, GA, November 2010.

“From Resource Acquisition to Relationships: How Energy Efficiency Initiatives Can Work Effectively with Large Commercial & Industrial Customers,” (with E. Belliveau, J. Kleinman, D. Gaherty, and G. Eaton), *2008 ACEEE Summer Study on Energy Efficiency in Buildings,* Pacific Grove, CA, August 2008.

National Action Plan for Energy Efficiency (2007). *Guide for Conducting Energy Efficiency Potential Studies.* Prepared by Philip Mosenthal and Jeff Loiter, Optimal Energy, Inc. December.

Loiter J.M and V. Norberg-Bohm (1999), “Technology policy and renewable energy: public roles in the development of new technologies,” *Energy Policy* Vol.27 no.85-97

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Director: Gegax, Douglas
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Use Great Caution in Design of Residential Demand Charges

Jim Lazar

For decades, electricity prices for larger commercial and industrial customers have included demand charges, which recover a portion of the revenue requirement based on the customer's highest usage during the month. Data being collected through smart meters allows utilities to consider expanding the use of demand charges to residential consumers.

Data being collected through smart meters allows utilities to consider expanding the use of demand charges to residential consumers.

Great caution should be applied when considering the use of demand charges, particularly for smaller commercial and residential users. Severe cost shifting may occur. Time-varying energy charges result in more equitable cost allocation, reduce bill volatility, and improve customer understanding. The caution applied should address the following key issues in most demand-charge rate designs:

- *Diversity:* Different customers use capacity at different times of the day, and these customers should share the cost of this capacity.
- *Impact on Low-Use Customers:* Most demand-charge rate designs have the effect of increasing bills to low-use customers, including the vast majority of low-income customers.
- *Multifamily Dwellings:* The utility never serves individual customer demands in apartment buildings, only the combined demand of many customers at the transformer bank.
- *Time Variation:* If demand charges are not focused on the key peak hours of system usage, they send the wrong price signal to customers.

Jim Lazar (jlazar@raponline.org) is a senior advisor at the Regulatory Assistance Project.

In the recent Regulatory Assistance Project (RAP) publication *Smart Rate Design for a Smart Future,*[1] we looked at many attributes of rate design for residential and small commercial consumers. We identified three key principles for rate design:

- A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- Customers should pay for power supply and grid services based on how much these customers use and when they use it.
- Customers supplying power to the grid should receive full and fair compensation—no more and no less.

Applying these principles results in an illustrative rate design that constructively applies costing principles in a manner that consumers can understand and respond to. **Exhibit 1** shows the illustrative rate design, including a customer charge for customer-specific billing costs and a demand charge for customer-specific transformer capacity costs. The exhibit also includes a time-varying energy price to recover distribution

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Exhibit 1. Illustrative Rate Design

Illustrative Residential Rate Design

Rate Element	Based On the Cost Of	Illustrative Rate
Customer Charge	Service Drop, Billing, and Collection Only	$4.00/month
Transformer Charge	Final Line Transformer	$1/kVA/month
Off-Peak Energy	Baseload Resources + Transmission and Distribution	$.07/kWh
Mid-Peak Energy	Baseload + Intermediate Resources + T&D	$.09/kWh
On-Peak Energy	Baseload, Intermediate, and Peaking Resources + T&D	$.14/kWh
Critical Peak Energy (or PTR)	Demand Response Resources	$.74/kWh

Source: Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future.* Montpelier, VT: Regulatory Assistance Project. Retrieved from http://raponline.org/document/download/id/7680.

system capacity costs and power supply costs designed to align prices with long-run marginal costs.

Customers can and will respond to rate design. We need to make sure that their actions actually serve to maximize their value and minimize long-run electric system costs. The illustrative rate is clearly directed toward these ends.

DEMAND CHARGES HAVE ALWAYS BEEN ONLY AN APPROXIMATION

Demand charges are imposed based on a customer's demand for electricity, typically measured by the highest one-hour (or 15-minute) usage during a month. Demand charges are sometimes coupled with a "ratchet" provision that charges the customer on the basis of the highest measured demand over the previous 12-month period or other multi-billing-period span of time.

Demand charges are imposed based on a customer's demand for electricity, typically measured by the highest one-hour (or 15-minute) usage during a month.

Exhibit 2 is a typical medium commercial rate design. It includes a demand component.

Utilities often justified demand charges on the basis of two arguments. First, they were

Exhibit 2. Illustrative Demand Charge Rate

Basic Tariff For Large Commercial Customer

Rate Element	Price
Customer Charge $/month	$20.00
Demand Charge $/kW/month	$10.00
Energy Charge $/kWh	$0.08

Key Terms for Demand Charges

CP: coincident peak demand: the customer's usage at the time of the system peak demand.

NCP: non-coincident peak demand: the customer's highest usage during the month, whenever it occurs.

Diversity: the difference between the sum of customer NCP and the system CP demands.

asserted as a "fairness" rate that assured that all customers paid some share of the utilities' system capacity costs. Second, especially when coupled with ratchets, they had the effect of stabilizing revenues.

Residential consumers have much more diversity in their usage, with individual customer maximum demands seldom coinciding with the system peak.

But demand charges are a shortcut, measuring each customer's individual highest usage during a month, regardless of whether the usage was coincident with the system peak. The customer's individual peak was used as a proxy for that customer's contribution to system capacity costs. Demand charges were implemented in this way even though customers' individual demands did not coincide with the peak system demand, or more accurately, with the coincident peak for the individual components of the system involved, each of which may have peaks different from the system peak. This was always a "second-best" approach. It is roughly accurate for large commercial customers, because their highest usage *usually* (but not always) coincided with the system peak.

Residential consumers have much more diversity in their usage, with individual customer maximum demands seldom coinciding with the system peak. The rough accuracy that exists for using non-coincident peak (NCP) demand charges for large commercial customers is woefully inaccurate for residential consumers. But coincident-peak (CP) demand charges have other shortcomings, leaving some customers with more than their share of costs and others with none at all, as shown in **Exhibit 3**.

With data from smart meters, utility regulators can be more targeted in how costs are recovered, focusing on well-defined peak and off-peak periods of the month, not just a single hour of usage.

Today, with data from smart meters, utility regulators can be more targeted in how costs are recovered, focusing on well-defined peak and off-peak periods of the month, not just a single hour

Exhibit 3. Garfield and Lovejoy Criteria and Alternative Rate Forms

Garfield and Lovejoy Criteria	CP Demand Charge	NCP Demand Charge	TOU Energy Charge
All customers should contribute to the recovery of capacity costs.	N	Y	Y
The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity.	N	N	Y
Any service making exclusive use of capacity should be assigned 100% of the relevant cost.	Y	N	Y
The allocation of capacity costs should change gradually with changes in the pattern of usage.	N	N	Y
Allocation of costs to one class should not be affected by how remaining costs are allocated to other classes.	N	N	Y
More demand costs should be allocated to usage on-peak than off-peak.	Y	N	Y
Interruptible service should be allocated less capacity costs, but still contribute something.	Y	N	Y

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of usage. This more precise usage data makes demand charges a largely antiquated approach for all customer classes—and particularly inappropriate for residential consumers.

DIVERSE USER PATTERNS VARY GREATLY

Residential customers use system capacity at different times of the day and year. Some people are early-risers, and others stay up late at night. Some shower in the morning, and some in the evening. Some have electric heat, and others have air conditioning.

This variability results in great diversity in usage. It is important to anticipate and recognize this diversity in choosing the method for recovery of system capacity costs. Demand charges are not very useful for this purpose.

A half-century ago, Garfield and Lovejoy discussed how system capacity costs should be reflected in rates.[2] Their observations, summarized in Exhibit 3, are as relevant today as when they were published. We compare the performance of three rate-design approaches to these criteria.

Variability results in great diversity in usage. It is important to anticipate and recognize this diversity in choosing the method for recovery of system capacity costs.

Following this guidance, capacity costs need to be recovered in every hour, with a concentration of these charges in system peak hours. The illustrative rate design in Exhibit 1 does this effectively. The typical commercial rate design in Exhibit 2, loading system capacity costs to an NCP demand charge, does not, because it recognizes only one hour of customer-specific demand.

Churches and stadiums illustrate this problem with demand charges. Churches have peak demands on days of worship—most often Wednesday nights and Sunday mornings, and stadium lights are used only a few hours per month, in the evening hours in the fall and winter. None of this usage is during typical peak periods.

Applying demand charges to recover system capacity costs based on non-coincident peak demand to churches and stadiums has long been recognized as inappropriate. Such charges have the effect of imposing system capacity costs on customers whose usage patterns contribute little, if anything, to the capacity design criteria of an electric utility system at the same rate as customers using that capacity during peak periods. The same problem applies for residential consumers.

On a typical distribution system, multiple residential consumers share a line transformer, and hundreds or thousands share a distribution feeder. The individual non-coincident demands of individual customers are not a basis for the sizing of the distribution feeder; only the combined demands influence this cost. Even at the transformer level, some level of diversity is assumed in determining whether to install a 25-kilovolt-amp or 50-kilovolt-amp transformer to serve a localized group of perhaps a dozen customers.

Demand charges applied on NCP ignore this diversity, charging a customer using power for one off-peak hour per month the same as another customer using power continuously for every hour of the month.

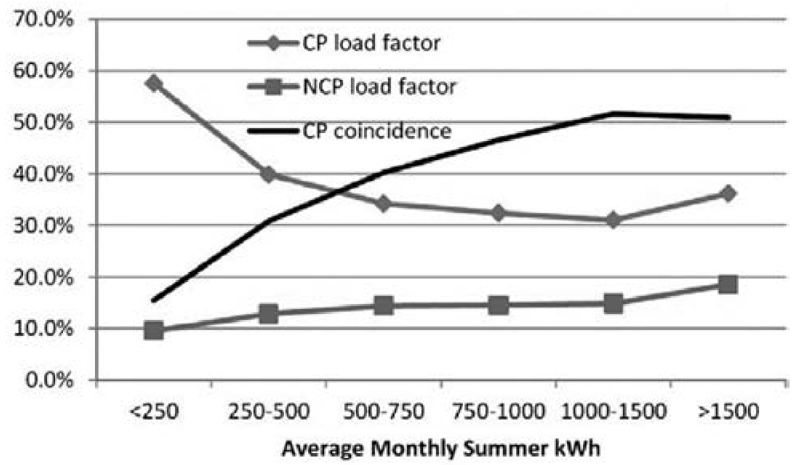
Demand charges applied on NCP ignore this diversity, charging a customer using power for one off-peak hour per month the same as another customer using power continuously for every hour of the month. Some customers (think of a doughnut shop and nightclub) use capacity only in the morning or evening, and can share capacity, while others (think of a 24-hour mini-mart) use capacity continuously and preempt this capacity from use by others. Modern rate design needs to distinguish between different characteristics in the usage of capacity and ensure all customers make an appropriate contribution to system capacity costs.

Time-varying rates do this very well, while simple CP and NCP demand charges do not.

IMPACT ON LOW-USE CUSTOMERS

Individual residences have very low individual customer load factors but quite average collective usage patterns.

Exhibit 4. Load Factors



Source: Marcus, B. (2015, June). Presentation at Western Conference of Public Service Commissioners, Phoenix, AZ.

Exhibit 4 shows data from Southern California Edison Company. As is evident, while the individual customer load factors of small-use residential customers are only about 10 percent, their group coincident peak load factor is more like 60 percent, quite close to an overall system load factor. A demand charge based on NCP demand greatly overcharges these customers. Meanwhile, the high-use residential customers, who have more peak-oriented loads, would be undercharged with a simple NCP demand charge based on overall residential usage.

The evidence is that the effect is to shift costs to smaller-use customers.

Rate analysts have examined the impact of demand-charge rate designs on residential customers. The evidence is that the effect is to shift costs to smaller-use customers, with about 70 percent of small-use residential customers experiencing bill increases, and about 70 percent of large-use residential customers experiencing bill decreases, even before any shifting of load.[3]

APARTMENT DIVERSITY

About 30 percent of American households live in some sort of multifamily dwelling. Apartments generally have the lowest cost of service of any residential customer group, because the utility provides service to many customers at a single point of delivery through a transformer bank sized to their combined loads. Because the sum of individual customer NCP demand greatly exceeds the combined group demand the utility serves, and by a greater margin than for other customer subclasses, NCP demand charges shift costs inappropriately to these multifamily customers.

About 30 percent of American households live in some sort of multifamily dwelling.

Low-income consumers are more likely to reside in apartments, and nationally, low-income household usage is about 70 percent of average household usage.[4] Therefore, imposing NCP demand charges on residential consumers, without separate treatment of apartments, would have a serious adverse impact on these customers, many of whom are

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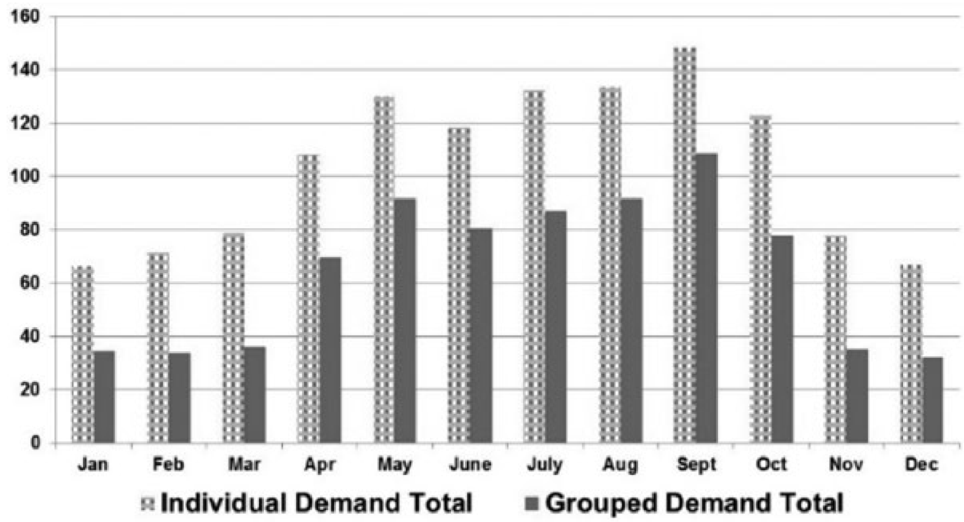
Exhibit 5. Individual and Group Peaks for a 26-Unit Apartment Building



Source: Author, from data supplied by Los Angeles–area municipal utility.

low-income households and often strain to pay their electric bills.

Exhibit 5 shows the sum of individual customer monthly non-coincident peaks for a 26-unit apartment complex in the Los Angeles area, and the monthly group peaks of these customers actually seen by the utility at the transformer bank serving the complex. The exhibit shows that billing customers on the basis of non-coincident peak demand would dramatically overstate the group responsibility for system capacity costs.

TIME-VARYING COST RECOVERY

As expressed by Garfield and Lovejoy, the optimal way to recover system capacity costs is through a time-varying rate design. This can be as simple as a higher charge for usage during on-peak hours than off-peak hours, or it can be a fully dynamic hourly time-varying energy rate. What is clear is that a single demand charge, applied to a single one-hour NCP or CP measure of demand, is unfair to those customers whose usage patterns allow the shared use of system capacity.

Some utilities have implemented time-varying demand charges. California investor-owned utilities impose NCP demand charges for distribution costs, and CP demand charges for generation and transmission capacity on larger commercial consumers. More recently, some utilities have imposed demand charges on smaller customers based on summer on-peak-hour demands only. All of these reflect gradual movement toward equitable recovery of system capacity costs, but full time-of-use (TOU) energy pricing is more effective, more cost-based, more equitable, and more understandable.

Today, with interval data from smart meters, we can easily collect data on the actual usage during each hour of the month.

Today, with interval data from smart meters, we can easily collect data on the actual usage during each hour of the month. Usage during peak periods can be assigned the costs of peaking power supply resources and seldom-used distribution system capacity costs installed for peak hours. Usage during other hours can be assigned the cost of baseload resources and the basic distribution infrastructure needed to deliver that power.

The pricing can be as granular as the analyst chooses and the regulator approves—but a key element of rate design is simplicity. For that reason, most analysts shy away from rate design with more than three time periods and a few rate elements.

The illustrative rate design in Exhibit 1 shows a three-period TOU plus critical peak price for both power supply and distribution capacity cost recovery, a customer charge for billing costs, and a demand charge to recover the cost of the final line transformer. It may be as complex a rate design as most residential consumers will reliably understand.

TRANSITIONING TO A TOU RATE DESIGN

Many customer groups are apprehensive about time-varying utility rates, because some consumers will receive higher bills and may not be able easily to change their usage patterns. This same concern would apply to implementation of a demand-charge rate design, but because that produces a less desirable result, we do not consider it a meaningful option. There are the following tools that can be used for a transition:

- *Shadow billing:* Provide consumers with *both* the current rate design and the proposed TOU rate design calculated on the bill prior to rollout.
- *Load control:* Prior to implementing a TOU rate, assist customers to install controls on their major appliances to ensure against inadvertent usage during on-peak periods.
- *Customer-selected TOU periods:* The Salt River Project in Arizona has had excellent success allowing customers to choose a three-hour "on-peak" period out of a four-hour system peak period.[5]

COMMON ERRORS IN DEMAND-CHARGE DESIGN

Common errors include the following:

- *Upstream Distribution Costs:* Any capacity costs upstream of the point of customer connection can be accurately assigned to usage and recovered in time-varying prices.
- *Using NCP Demand:* NCP demand is not relevant to any system design or investment criteria above the final line transformer, and only there if the transformer serves just a single customer.
- *Accounting for Diversity:* Diversity is greatest among small-use customers and needs to be fully accounted for.
- *Apartments:* Apartments have the lowest cost of service of any residential customer group, the highest diversity, and suffer the most when a single rate design is applied to all residential customers.

GUIDANCE FOR COST-BASED DEMAND CHARGES

The following guidelines can be used;

- Limit any demand charges to customer-specific capacity.
- Fully recognize customer load diversity in rate design.
- Demand charges upstream of the customer connection, if any, should apply only to the customer's contribution to system coincident peak demand.
- Compute any demand charges on a multi-hour basis to avoid bill volatility.

Modern metering and data systems make it possible to increase greatly the accuracy, and therefore the fairness, of cost allocation among a diverse customer base. Legacy concepts, such as demand charges, especially those based on NCP demand, prevent the implementation of these improvements and should be eliminated. Time-varying cost assignment is preferred, so that these new technologies can deliver their full value to customers and utilities alike.

NOTES

1. Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future.* Montpelier, VT: Regulatory Assistance Project. Retrieved from http://raponline.org/document/download/id/7680.
2. Garfield, P. J., & Lovejoy, W. F. (1964). *Public utility economics*. Englewood Cliffs, NJ: Prentice Hall; pp. 163–164.
3. Hledik, R. (2015). *The landscape of residential demand charges*. Presented at the EUCI Demand Charge Summit, Denver.
4. Testimony of John Howat, National Consumer Law Center, Indiana Utility Regulatory Commission, Cause No. 44576, 2015.
5. SRP "EZ-3" Rate. Retrieved from http://www.srpnet.com/prices/home/ChooseYourPricePlan.aspx.

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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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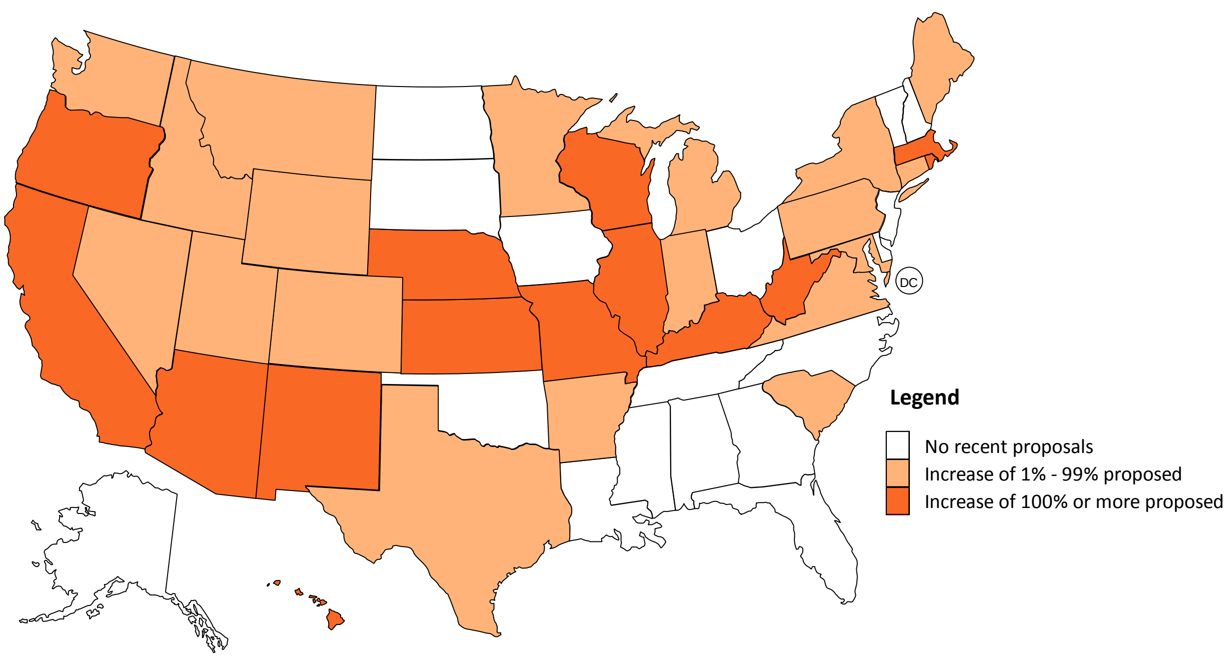
CONTENTS

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."*

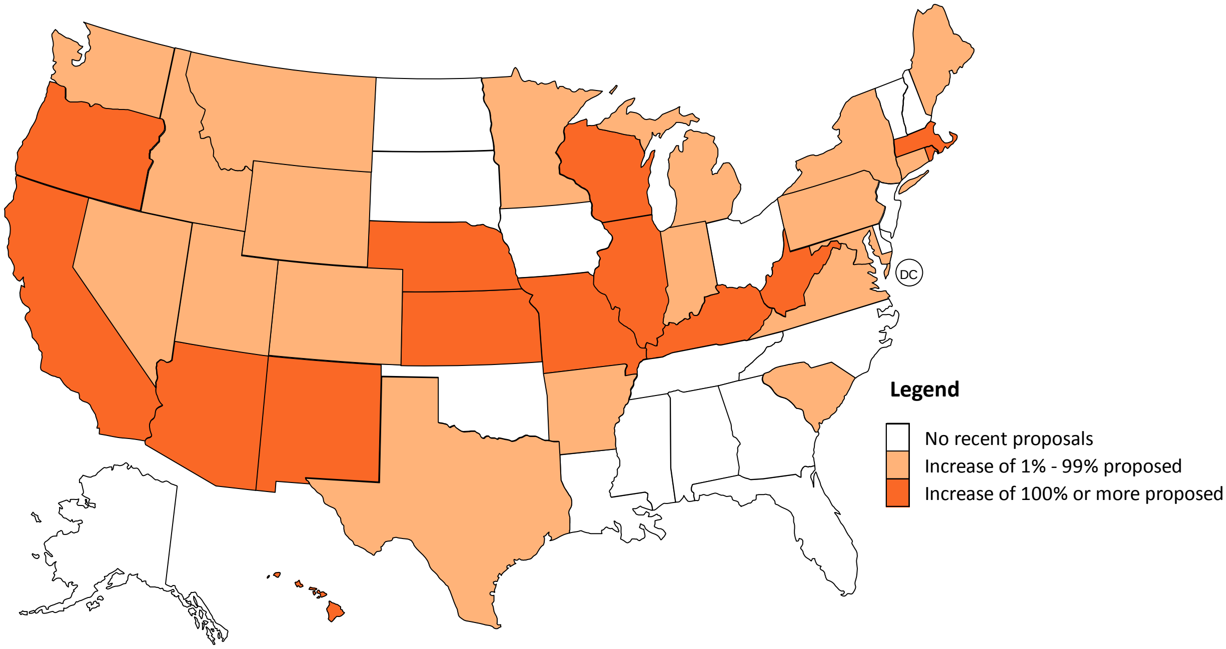
The map below shows the prevalence of recent utility proposals to increase the fixed charge, as well as the relative magnitude of these proposals. Proposals to increase the fixed charge were put forth or decided in 32 states in 2014 and 2015. In 14 of these states, the utility's proposal would increase 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.

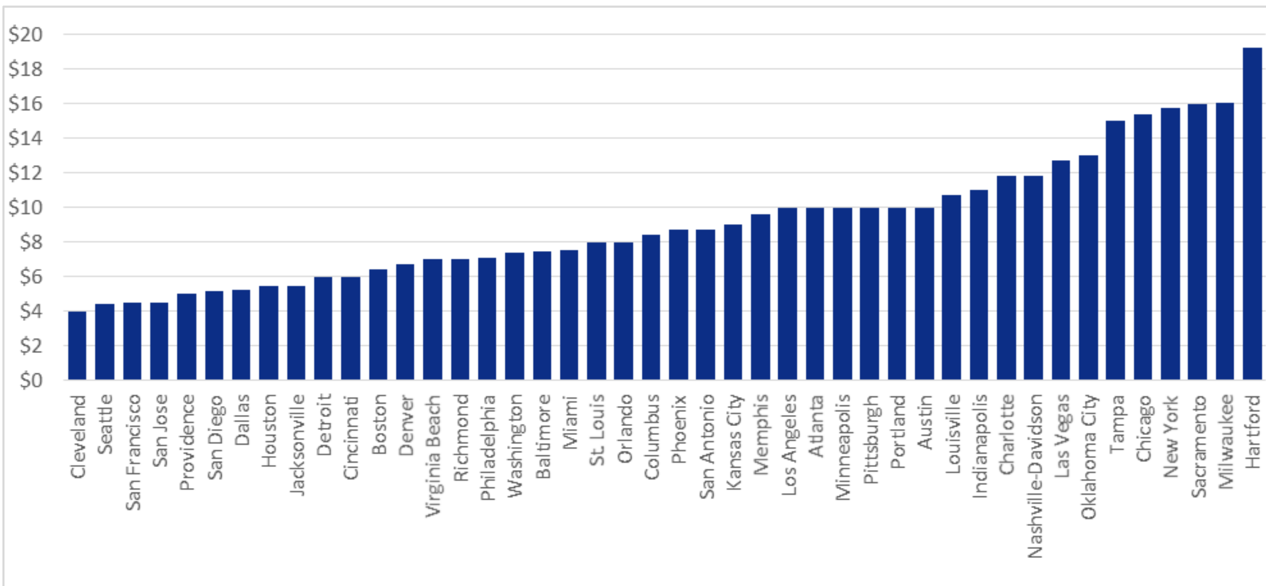
[5] Senate Bill No. 1502, June Special Session, Public Act No. 15-5, "An Act Implementing Provisions of the State Budget for The Biennium Ending June 30, 2017, Concerning General Government, Education, Health and Human Services and Bonds of the State."

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.

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[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.

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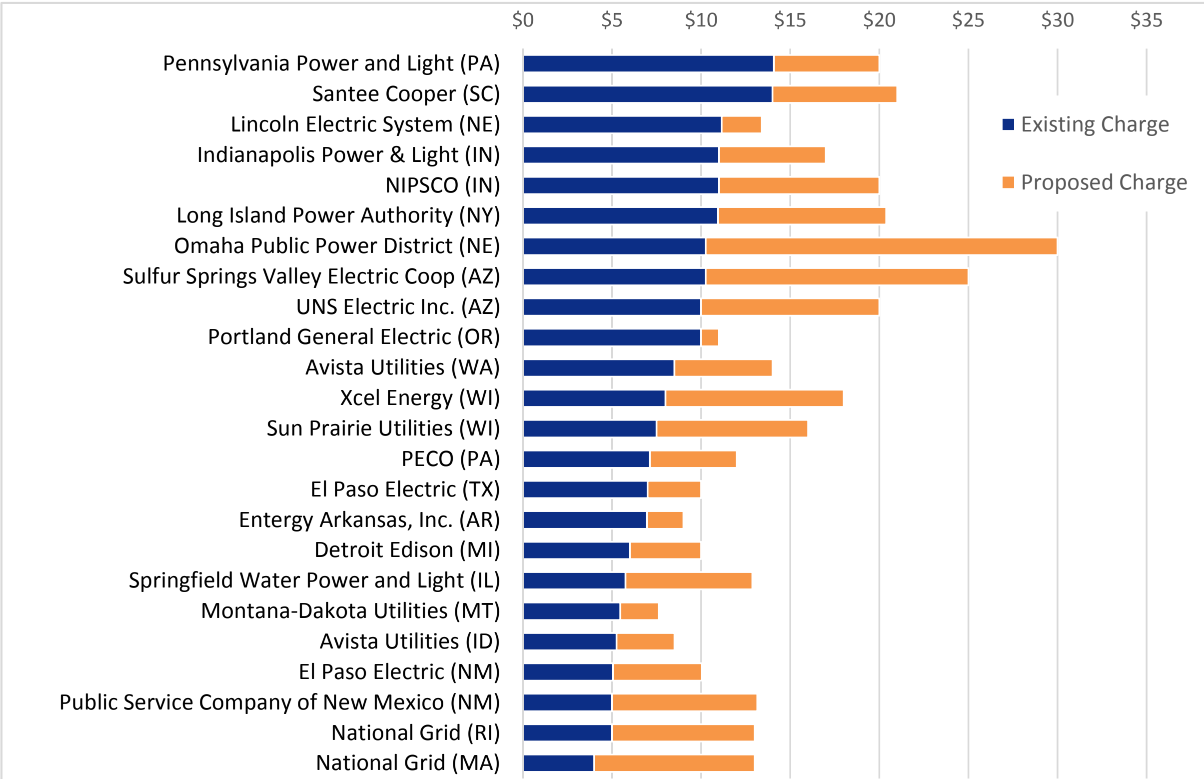
[8] Ultimately the commission approved a fixed charge of $19.25, below the utility's request, but among the highest in the country.

[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.

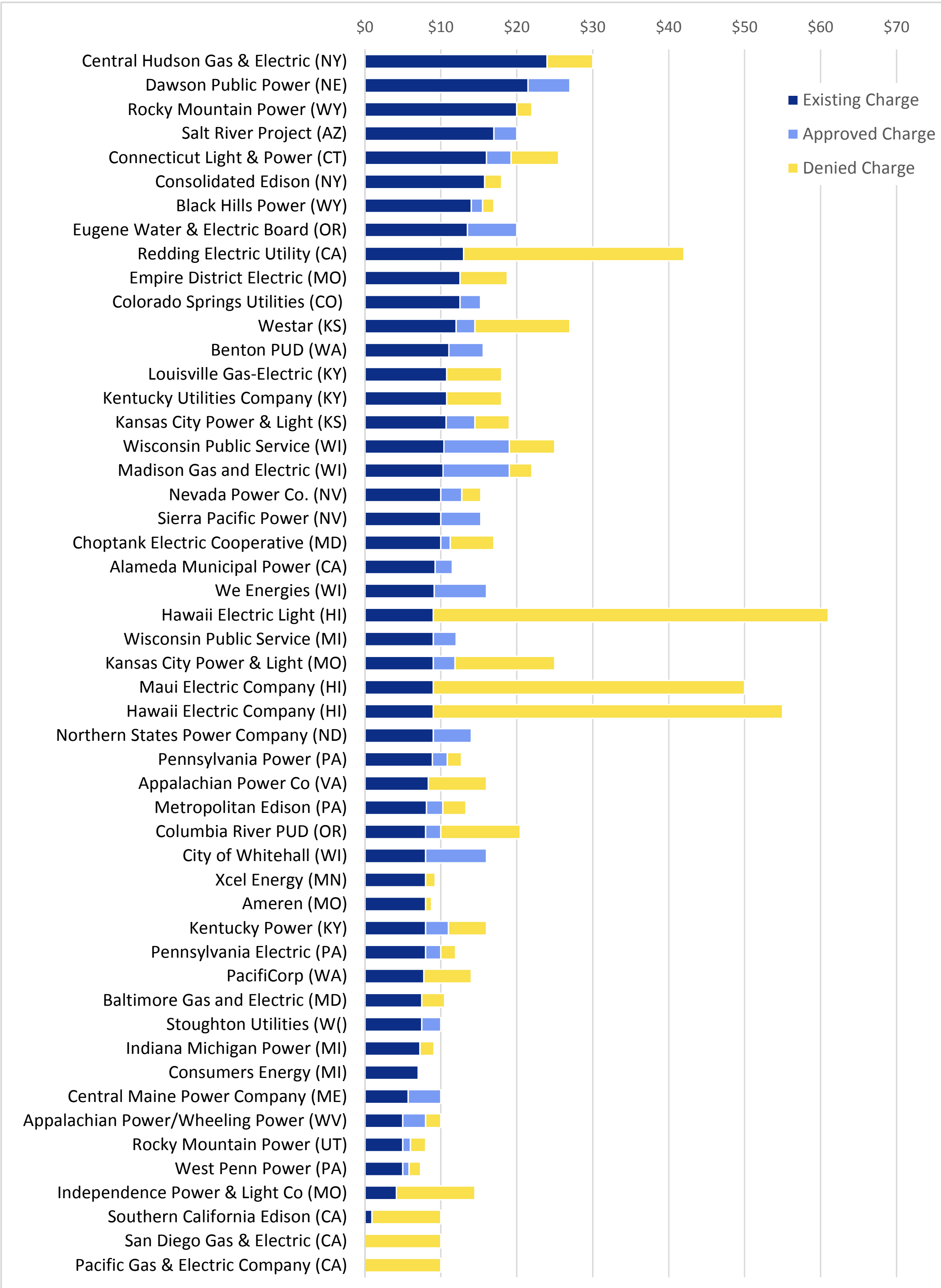
[11] PPL Witness Scott R. Koch, Exhibit SRK 1, Supplement No. 179 to Tariff – Electric Pa. P.U.C. No. 201, Docket No. R-2015-2469275, March 31, 2015, at http://www.puc.state.pa.us/pcdocs/1350814.pdf.

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.

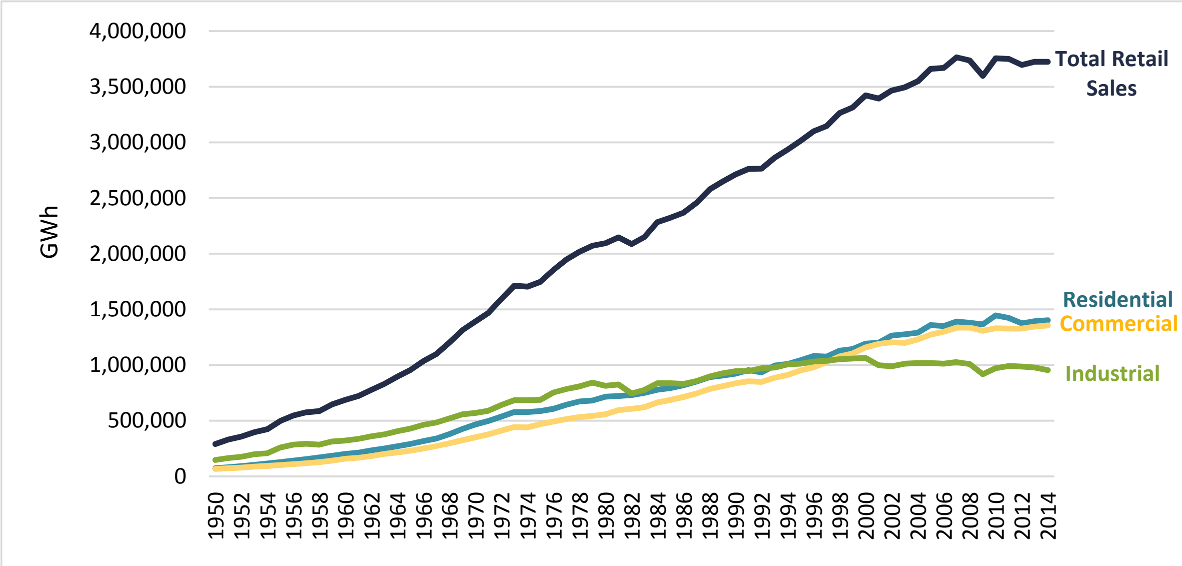
Rates are typically composed of some combination of the following three types of charges:

- 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

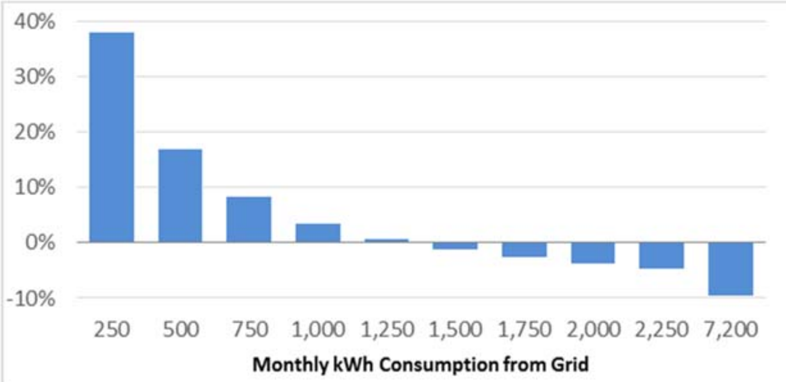
Customers who use less energy than average will experience the greatest percentage jump in their electric bills when the fixed charge is raised, since bills will then be based less on usage and more on a flat-fee structure. There are many reasons why a customer might have low energy usage. Low-usage 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

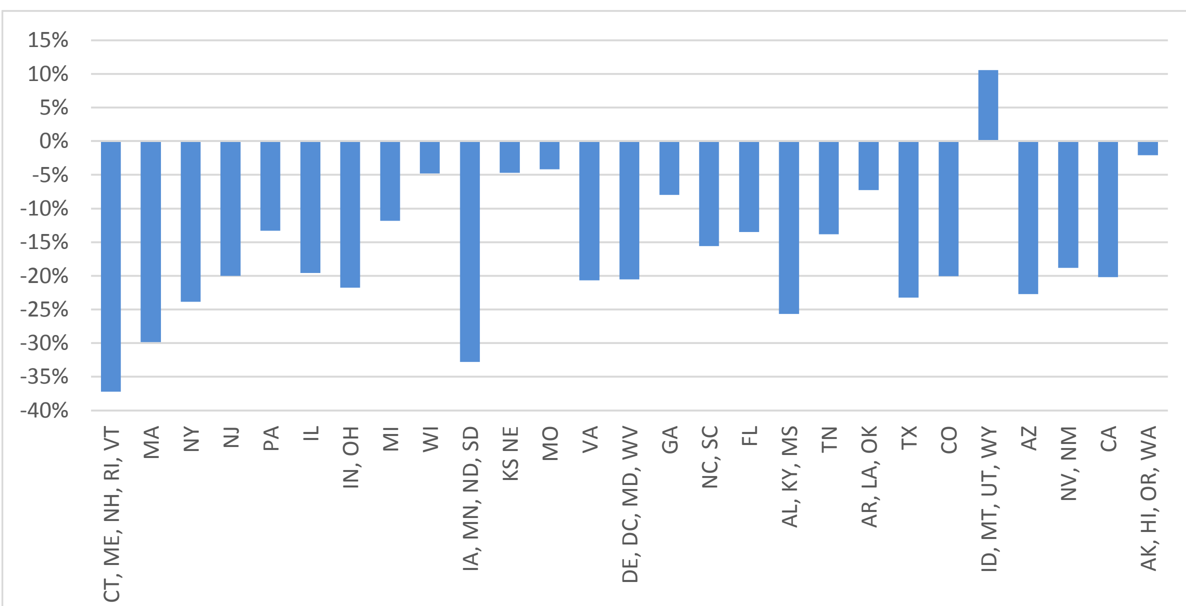


Analysis based on increasing the fixed charge from $9/month to $25/month, with a corresponding decrease in the $/kWh charge.

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.

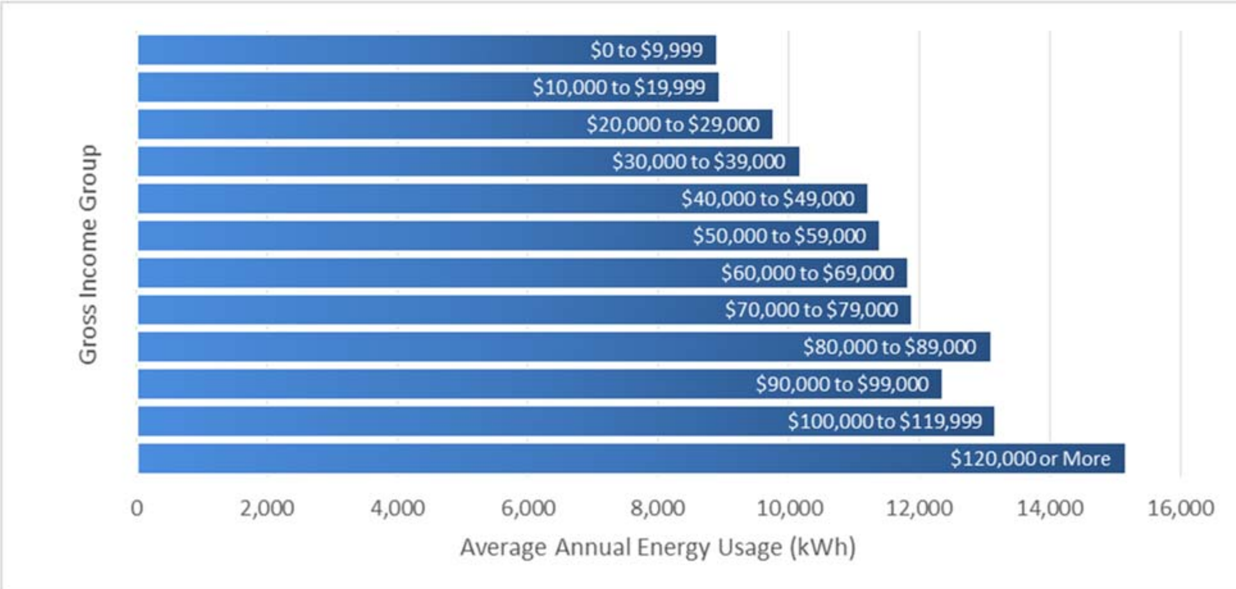
Figure 7. Difference between low-income median residential electricity usage and non-low-income usage



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.

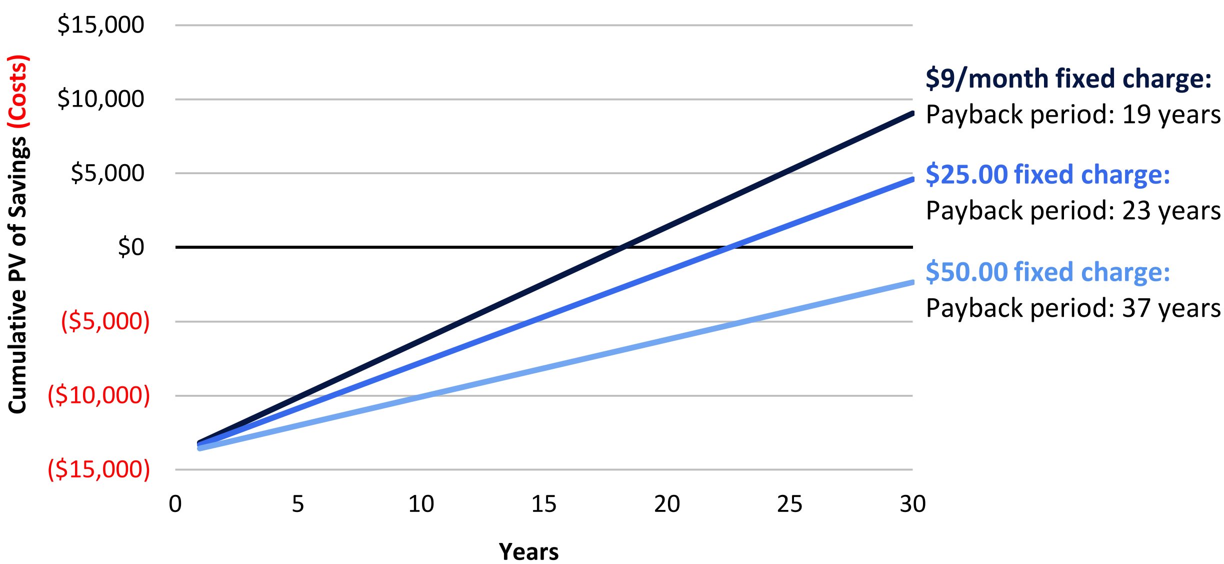
[17] Annie Gilleo et al., "The 2014 State Energy Efficiency Scorecard" (American Council for an Energy Efficient Economy, October 2014).

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.

Response

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.

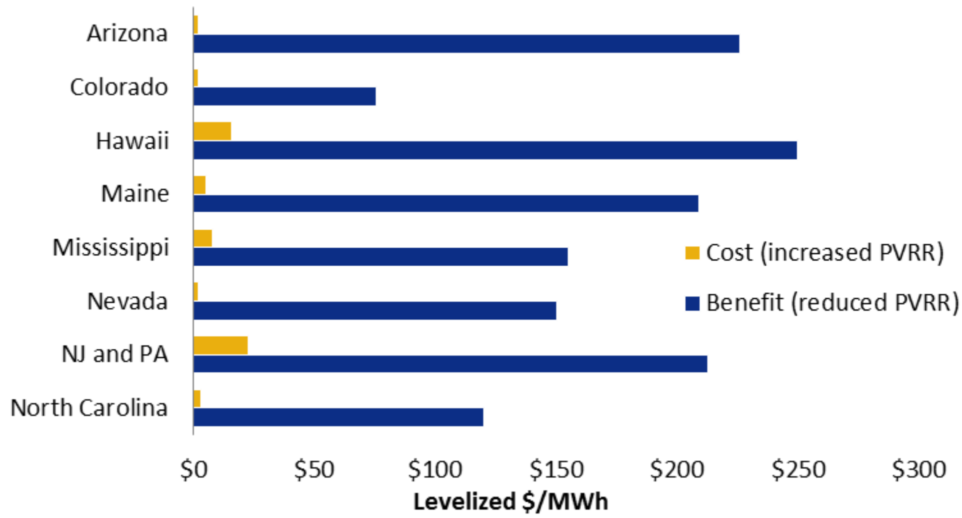
The benefits of distributed generation, in terms of reduced revenue requirements, will significantly reduce, and may even eliminate, any cost-shifting that might occur.

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.

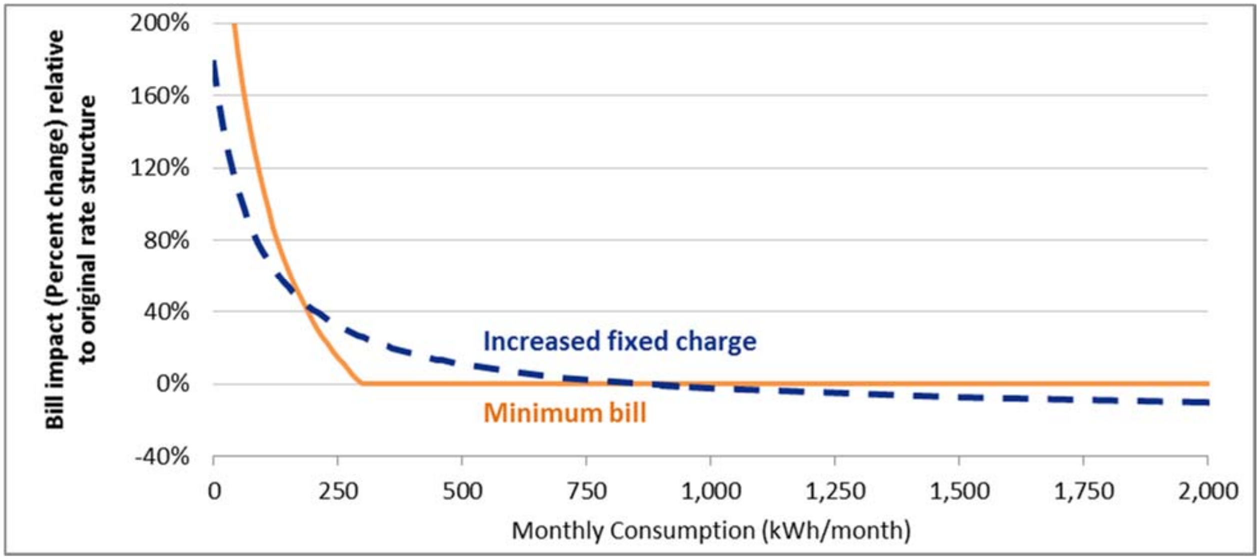
Under the minimum bill option, only customers with usage less than 280 kWh per month (approximately 5 percent of customers at a representative Midwestern utility) would see a change in their bills, and most of these customers would see an increase in their monthly bill of less than $10.

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.

[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

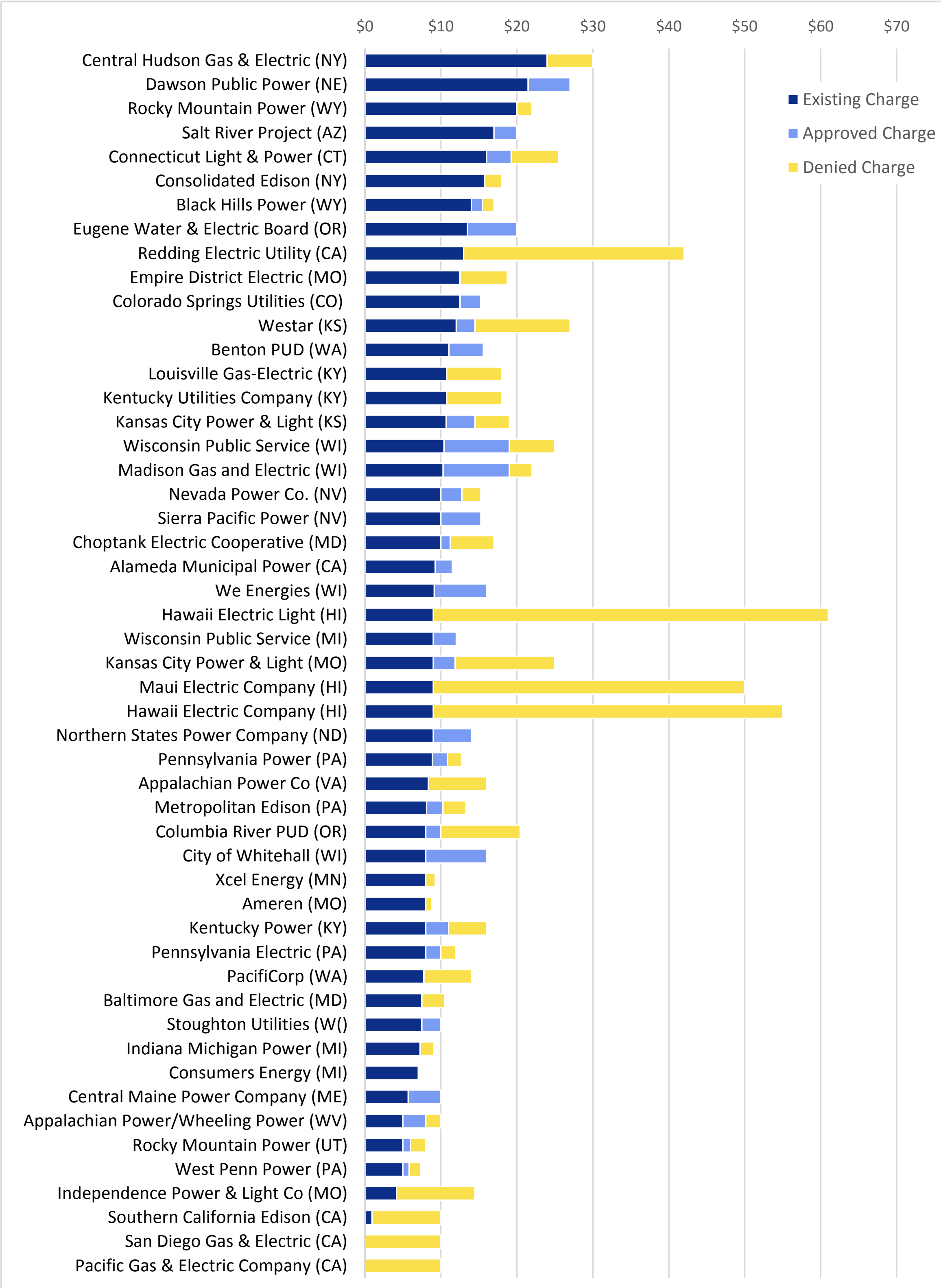
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

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		

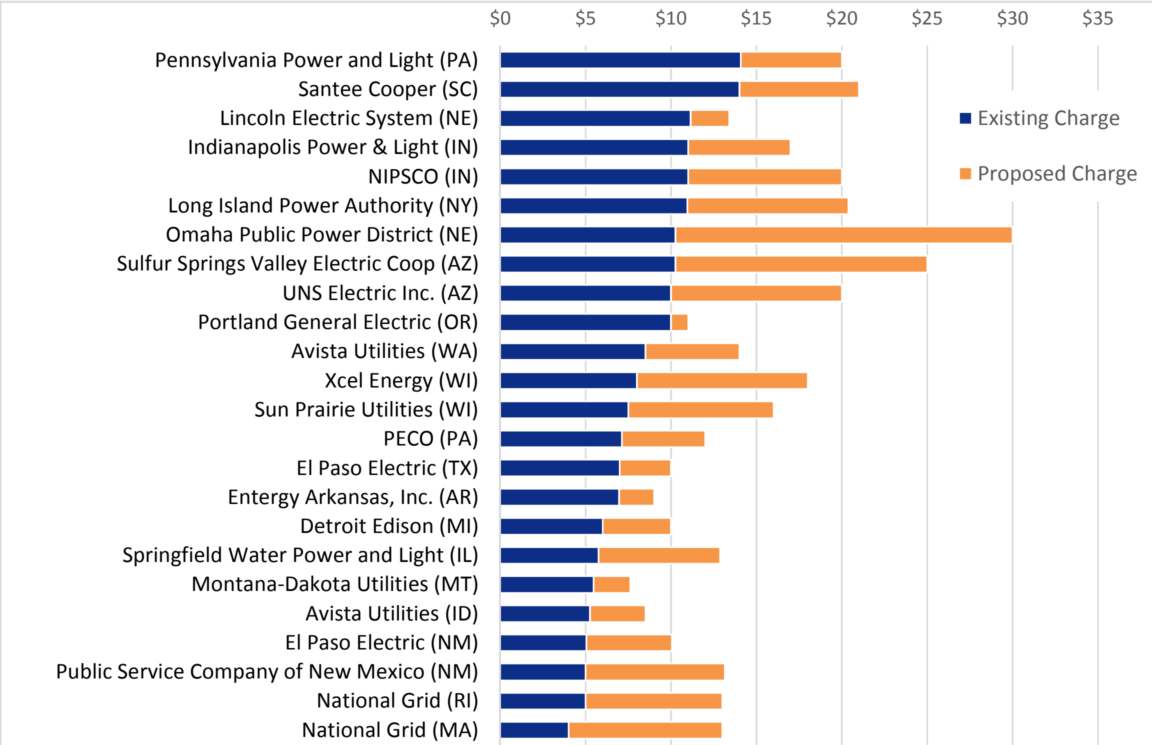
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

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

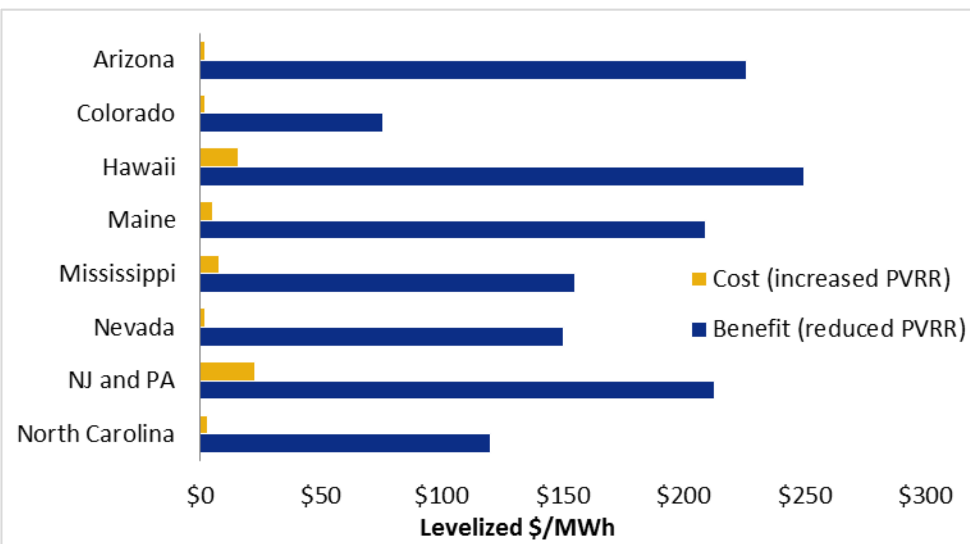


Appendix C – Net Metering Impacts on Utility Costs

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

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[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.

A Troubling Trend in Rate Design:

Proposed Rate Design Alternatives to Harmful Fixed Charges

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INTRODUCTION

In recent years, many electric utilities have experienced reduced customer usage driven in part by increased deployment of distributed energy resources ("DERs"). DERs include distributed generation, demand-response programs, and energy efficiency measures. They are frequently installed by the customer at his or her own cost. The rise of DERs has prompted concern by some utilities that flat or declining sales will generate insufficient revenue to cover the fixed costs of maintaining the grid. In response, some utilities have proposed imposing higher fixed charges on their customers. Fixed charges, also known as customer charges or access fees, are fees customers pay for electric service that do not vary with usage. Because they are fixed, the charges cannot be avoided through measures such as energy efficiency or customer-sited renewable resources.

Utilities adopting higher fixed charges may view them as a quick fix—they provide short-term revenue stability and are relatively simple to administer. The reality, though, is that high fixed charges are bad for customers, and ultimately, the utility. High fixed charges harm many customers, especially those with lower incomes who live in smaller homes or apartments, and those with lower electric demands. Further, high fixed charges fail to provide accurate price signals to customers, which are essential for promoting customer investment in DERs and the system-wide benefits they can provide, such as reducing the need for new, high-cost centralized generation capacity. Lastly, high fixed charges are frequently perceived by customers as an effort to punish them for buying less of the utility's product.

Fundamentally, high fixed charges reflect a failure by utilities to consider a range of smart rate design opportunities that better respond to the changing nature of the grid.

Electricity rate design refers to the pricing structure used by utilities to determine customer bills. It is based on short and long-term utility costs that reflect past, and drive future investment choices. Rate design determines the price signals consumers use to guide their consumption and investment choices. Historically, for residential and small business customers, rates have generally been structured as volumetric energy rates—customers pay a single rate multiplied by the kilowatt-hours ("kWh") of energy used—with a modest monthly customer charge to cover billing and collection costs. For higher-volume customers, such as large commercial or industrial customers, utilities have divided rates into three parts: 1) a mandatory fee to cover billing and collection costs; 2) a volumetric per-kWh energy price and 3) a demand charge, based on peak kilowatt ("kW") demand. Under these rate-design structures, utilities' ability to recover costs are directly tied to customer consumption, with fixed charges only covering the costs that directly vary with each additional customer served.[1]

"Smart rate design" refers to an approach to rate design that more accurately aligns utility costs with customer bills, and which better reflects the time- and location-specific costs of delivering electricity. Smart rate design allows utilities sufficient revenue without diluting the customer's incentive to deploy DERs.

Smart rate design options include time-of-use and other time-varying rates; well-designed minimum bills; and location-based and attribute pricing. Additionally, revenue decoupling—which separates utility revenue recovery from kWh sales—allows utilities to ensure revenue requirements, independent of customer sales volume. Utilities utilizing smart meters will have greater opportunity to adopt smart rate design.

As the electricity market continues to evolve as a result of DERs and smart-grid development, utilities, particularly distribution utilities, are in a unique position to respond to the changing nature of the grid with smart rate design mechanisms to ensure system cost recovery, serve customer interests, and harness new technologies to decrease costs. However, utilities that choose not to utilize smart rate design and instead implement high fixed charges create a barrier to these opportunities for themselves and for their customers.

Some utilities argue that because many of their electric services costs are fixed, customer fees should also be fixed. They claim that recovering fixed infrastructure and operations costs through volumetric pricing or per-kWh charges raises utility risk, which can in turn lead to increases in their cost of capital, and ultimately, in the rates they charge customers. These utilities believe that fixed charges are the best way to recover their costs and sustain their business model.

However, there are serious short- and long-term downsides to fixed charges. Fixed charges negatively impact certain customer classes and income groups, discourage energy conservation, encourage unnecessary generation and distribution capacity investment, and discourage the development of DERs. These impacts are discussed below.

High Fixed Charges Disproportionately Impact Low-use and Low-income Customers

When utilities impose high fixed charges, they increase the proportion of their revenue requirements recovered through such charges, and decrease the proportion recovered through a volumetric, per-kWh energy rate. Thus, high fixed charges inherently penalize low-use customers, who are often low-income customers, apartment residents, or small businesses, resulting in proportionally higher electric bills for those customers. This is particularly harmful for low-income customers and those on fixed incomes, such as the elderly, who are often already on tight budgets and for whom energy costs consume a disproportionate share of household income.

Table 1 shows a comparison of the usage of low-income consumers to other consumers, for every state.

Table 1
Average 2009 Household Electricity Usage by Status Above or Below 150% of Poverty
kWh

Energy Information Administration, Residential Energy Consumption Survey Reportable Domain	Household Income: Above 150% Poverty Level	Household Income: At or Below 150% Poverty Level	Household Income: All Households	Percentage Difference between average KWH low-income and non-low-income households
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	7,468	4,709	6,961	-37.0%
Massachusetts	6,056	4,222	5,686	-30.3%
New York	5,969	4,544	5,355	-23.9%
New Jersey	7,497	4,969	7,231	-33.7%
Pennsylvania	9,690	8,402	9,306	-13.3%
Illinois	9,116	7,350	8,432	-19.7%
Indiana, Ohio	9,999	7,831	9,365	-21.7%
Michigan	8,190	7,073	7,764	-13.6%
Wisconsin	7,889	7,449	7,727	-5.6%
Iowa, Minnesota, North Dakota, South Dakota	9,285	6,241	8,940	-32.8%
Kansas, Nebraska	9,402	8,808	9,302	-6.3%
Missouri	12,232	11,705	11,991	-4.3%
Virginia	13,859	10,997	13,231	-20.7%
Delaware, District of Columbia, Maryland, West Virginia	13,063	10,381	12,848	-20.5%
Georgia	13,816	12,727	13,499	-7.9%
North Carolina, South Carolina	14,343	12,105	13,651	-15.6%
Florida	13,760	11,905	13,212	-13.5%
Alabama, Kentucky, Mississippi	15,847	11,802	14,656	-25.5%
Tennessee	14,480	12,537	13,782	-13.4%
Arkansas, Louisiana, Oklahoma	13,646	12,628	13,421	-7.5%
Texas	13,799	10,602	12,878	-23.2%
Colorado	6,516	5,216	6,231	-20.0%
Idaho, Montana, Utah, Wyoming	9,588	10,665	9,804	11.2%
Arizona	13,056	10,088	12,105	-22.7%
Nevada, New Mexico	9,434	7,637	9,164	-19.0%
California	5,939	4,739	5,628	-20.2%
Alaska, Hawaii, Oregon, Washington	10,799	10,597	10,754	-1.9%
Total	10,072	8,432	9,687	-16.3%

Source: 2009 EIA Residential Energy Consumption Survey data by "Reportable Domain," July 2015, Tabulated by National Consumer Law Center, July 2015, John Howat – jhowat@nclc.org.

While the empirical research is currently divided on how low-income customers would respond to specific smart rate designs, it is clear that limiting customers' ability to reduce monthly bills—which is what fixed charges do—would have negative impacts on these vulnerable populations.[2] Additionally, fixed charges negatively impact both urban and rural residents who use natural gas for space and water heat. Such customers receive proportionately higher electric bills as a result of high fixed charges, because heating costs are not reflected in their electric bill.[3] In other words, high fixed charges result in a greater percentage increase in electric bills for those that heat with non-electric fuels.

Higher fixed charges are inequitable for apartment-dwelling urban residents in particular, because they are the lower-cost group of residential customers to serve, simply because the number of customers per transformer and per mile of distribution circuit is higher than for suburban or rural single-family dwellings. If distribution costs are recovered through high fixed charges, higher-cost suburban and rural single-family customers with higher usage see reduced bills—an inequitable result.[4]

High Fixed Charges Undermine Investments in Energy Efficiency

Energy efficiency and conservation reduce customer bills, and they also reduce overall system costs. By reducing peak demands on the utility, energy efficiency and conservation help avoid expensive new capacity upgrades, and by displacing fossil generation, these customer initiatives also reduce carbon emissions. With higher fixed charges, customers have less incentive to reduce their electricity consumption because they are charged a high fixed rate regardless of their energy usage. Often, utilities that implement high fixed charges will simultaneously decrease their per-kWh energy charges with the result that customers' increased usage may not lead to a significant increase in their bill. This encourages wasteful consumption and hinders investment in energy efficiency.

For example, the Regulatory Assistance Project ("RAP") recently found that, compared to a flat volumetric rate, a high fixed charge rate design advocated by utilities in Ohio, Wisconsin, and Illinois could result in a 7% increase in residential consumer usage. In contrast, an inclining block residential rate with a low customer charge can achieve an 8% reduction in residential consumer usage.[5]

A study by the Kansas Corporation Commission reached similar conclusions. Researchers found that increased fixed charges in Kansas would increase electricity use by 1.1 – 6.8%, varying by utility and season.[6] To put this in perspective, the projected increase would be greater than all of the energy savings from all energy efficiency programs in the state. **The Commission found that such a change in rate structure and consumption would offset the financial benefits of decades of energy efficiency efforts and penalize customers who have already successfully invested in energy efficiency under previous rate structures.** Weakening the incentive to invest in energy efficiency could also have negative impacts for the local economy and the environment, as investments in energy efficiency are frequently accompanied by local efficiency jobs and pollution reduction.[7] Rate design that results in increased consumption would also greatly compound the challenges that utilities face in meeting the emission reductions required by the federal Clean Power Plan, which aims to reduce carbon emissions from power plants.

High Fixed Charges Can Encourage Utilities to Overbuild New Capacity Even as Electricity Demand Declines

High fixed charges, paired with per-kWh energy rates that do not account for the timing of use, also discourage peak demand reduction because they fail to provide accurate price signals about the times when electricity is most expensive to produce. High fixed charges signal to customers that increasing peak energy use does not increase costs and capacity requirements for the utility, when in fact the opposite is true. Without proper price signals for customers, consumption may increase in all periods, including peak periods. High peak demand, in turn, encourages utilities to overbuild new capacity.

Historically, utilities have built capacity and structured rates based on their ability to ensure peak demand is always met, even during rare high-demand moments. This approach has consistently resulted in utilities overbuilding capacity, and in particular, baseload capacity. For example, while the North American Reliability Council (“NERC”) standard for reserve capacity is around 15%, the U.S. Energy Information Administration’s (“EIA”) Summer 2014 energy forecast put unused generation capacity for the Carolinas at 24%, 26% for Tennessee, 37% for Georgia and Alabama, and 29% for Florida.[8] The costs of such excess capacity are an extra burden on ratepayers.

In recent years, electricity demand has slowed, and average usage has decreased, while peak usage has increased or remained the same.[9] The Southeast is no exception. Where previous estimates expected energy demand in the Southeast to grow by 3-4% per year, recent projections by EIA now estimate 1-2% growth. The expansion of DERs is contributing to the slowing of electricity demand growth in both residential and commercial buildings.[10] In some areas of the Southeast, residential demand for delivered electricity is expected to decline.[11]

This decreased consumption results in increased unused generation and grid infrastructure. As a result, utilities throughout the country and in the Southeast are being pressed to re-examine capacity needs and reforecast expected load growth. For example, TVA recently shifted its forecasted annual load growth from 3 or 4 percent a year to under 1 percent a year. While TVA previously expected to build an additional coal or natural gas unit every year, or a nuclear reactor every two or three years, it is now planning to retire plants and reduce its capacity expansion.[12] With a reduced need to invest in new capacity, TVA has the ability to offer lower long-term rates for its customers.

However, if the distribution utilities that serve customers in TVA’s territory begin to implement high fixed charges which result in increased consumption, this could signal to TVA the need to maintain or build more capacity and increase rates over the long term. For these reasons, high fixed charges have the potential to unfairly penalize all customers by depriving them of price signals that could prevent expensive capital investments and higher customer bills.

High Fixed Charges Discourage Customer Investment in DERs and Prevent the Benefits that Flow to the Grid from that Investment

DERs reduce energy consumption and produce substantial average monthly energy bill savings. Often, utilities claim that because customers with DERs significantly reduce their kWh consumption, they avoid paying their share of the fixed costs of the grid. These utilities argue that high fixed charges for DER customers are justified to prevent an unfair cost shift to non-DER customers. Utilities most frequently make this argument in regard to solar net metering policies (“NEM”) which compensate customers who send power back to the grid at rates equal to retail rates.

However, contrary to some utility claims, solar is projected to actually decrease system costs for utilities. A new study by Rocky Mountain Institute (“RMI”) projects that DER customers with solar and battery storage provide value to the grid by reducing peak demand, deferring or avoiding system upgrades, relieving congestion, and providing ancillary services.[13] In addition, other studies by utility regulators have found the value of distributed solar to exceed retail rates. **For example, Nevada regulators found that the value rooftop solar adds to the grid is 18.5 cents/kWh,[14] Mississippi 17 cents/kWh,[15] Maine 33.7 cents/kWh,[16] Minnesota 14.5 cents/kWh,[17] and Vermont 25.7 cents/kWh.[18]** Implementing fixed charges will only result in a missed opportunity for utilities to align the interests of customers using DERs with those of the grid as a whole.

Moreover, data from the residential solar market in Colorado shows that the typical residential customer who installs solar tends to have greater initial usage than an average customer, with an average monthly pre-solar bill of $126 compared to the average residential bill of $77 per month. After adding solar, the typical solar customer's bill drops to $50 per month.[19] In effect, adding solar changes a larger-than-average customer into a smaller-than-average one, but both are well within the range of sizes typical of the residential class.

In 2014, the Utah Public Service Commission reached a similar conclusion in rejecting a proposal from Rocky Mountain Power to impose a net metering facilities charge. In Utah, the typical residential customer uses 500-600 kWh per month, with net metered customers falling at the low end of this range at 518 kWh per month. The Utah commission concluded that "[t]hese facts undermine PacifiCorp's reasoning that net metered customers shift distribution costs to other residential customers in a fashion that warrants distinct rate treatment."[20]

SMART RATE ALTERNATIVE TO FIXED CHARGES

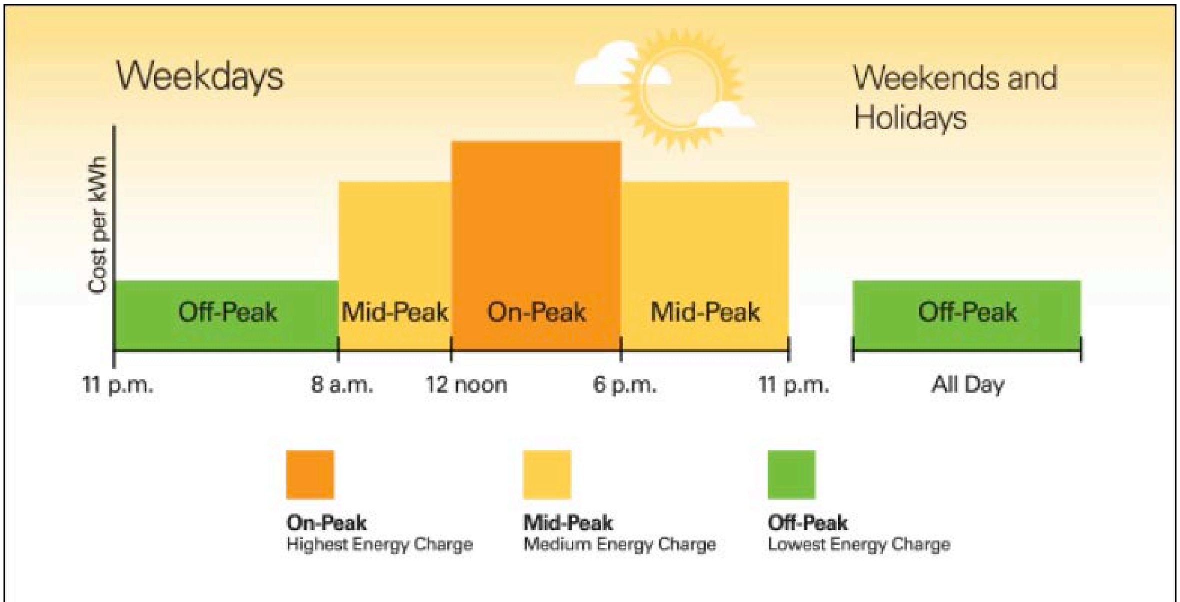
There are a variety of rate design structures that utilities can utilize to ensure fixed cost recovery without causing the negative effects of fixed charges. For years, electric industry experts have recognized the importance of smart rate design founded on mechanisms that send correct price signals to customers. A brief canvas of the literature reveals the following consistent principles of smart rate design.[21] Based on these principles, customer rates should:

- Be economically efficient, based on total system long-run marginal (not embedded) costs;
- Allow for customers to connect to the grid for no more than the cost of connection;
- Be comprehensible to the customer;
- Assure grid reliability;
- Recover system costs in proportion to how much electricity consumers use, and when they use it;
- Provide customers with the correct price signals about usage and consumption patterns;
- Fairly compensate customers who supply power to the grid at the power's full value;
- Allow for competition within the market for both generation and ancillary services;
- Assure recovery of utility's prudently incurred costs;
- Maintain fairness to all customer classes and subclasses;
- Maximize the value of new technologies as they become available; and
- When possible, be temporally and geographically dynamic.

Pursuing smarter rate design can reduce overall system costs while still allowing utilities to receive necessary revenue, create incentives for customers to implement solutions that serve utilities' interests, promote the integration of DERs, and ensure net benefits to the grid. Some of these rate design techniques include: time-of-use ("TOU") and other time-varying rates; well-designed minimum billing; and revenue decoupling. Advanced metering infrastructure—including smart meters—also allow utilities to implement even more granular rate designs, such as location-based rates and attribute pricing.

Time-of-Use Pricing

Instead of establishing higher fixed charges, utilities can expand offerings for time-varying rates, such as TOU or dynamic pricing structures. TOU pricing charges customers higher or lower rates based on the timing of energy use and the corresponding demand on the grid. TOU rates are usually set once or twice a year. Dynamic pricing—or Real-Time Pricing ("RTP")—is a more granular TOU rate that accounts for the hourly change in the cost of generation and more accurately reflects the short-run marginal value of power. While TOU rates are set annually or semi-annually, dynamic pricing may change each hour depending on the real-time cost of generation.[22]



Source: Southern California Edison: Time-of-Use Rate FAQs

TOU pricing is preferable to high fixed charges and flat volumetric rates because it sends more accurate price signals to customers that better reflect the costs to the utility to produce and deliver electricity. While fixed charges fail to capture marginal costs that can vary substantially over time and ignore changing electricity system conditions, TOU and RTP better account for the dynamic cost of energy generation, distribution, and service.[23] The structure of a TOU program can vary significantly, from simple on-peak and off-peak pricing, to seasonal TOU rates, to hourly-based RTP. For example, Nevada Energy's Residential on-peak TOU rate can reach 50 cents/kWh,[24] while Chattanooga EPB's residential, off-peak TOU rates are as low as 6.5 cents/kWh.[25] The efficiency and effectiveness of TOU pricing depend on its ability to reflect real-time changes in electricity conditions.[26]

At their simplest, TOU rates communicate to customers that the cost to produce and deliver electricity is much higher during peak hours than off-peak hours. For example, TOU customers receive the correct signal that turning up an air conditioner on a hot summer afternoon increases the cost and the need for new capacity over the long run.[27] In their more complex forms, such as RTP rates, time-varying rates provide a full picture of the hourly cost to produce and deliver electricity and give greater control to consumers to shift their behavior based on their needs and investment decisions.[28]

In a recent order, the Massachusetts Department of Public Utilities stated that TOU rates are an essential component of grid modernization.[29] Concerned that under the current basic service structure rates do not reflect the time-varying nature of electricity supply costs, the Department is requiring the incorporation of TOU rates for all customers.[30] The Department's recent order will require electric distribution companies to offer two basic service TOU options: 1) A default product with TOU pricing that includes a critical peak pricing ("CPP") component,[31] and 2) a flat rate with a peak time rebate ("PTR") option. Under CPP, utilities designate a number of "critical peak" days each year during which the price of electricity increases significantly. Utilities inform customers ahead of time when critical peak days will occur to allow customers to reduce consumption during CPP periods. Under PTR, utilities apply similar critical peak periods, but instead of charging customers higher rates during those periods, customers who reduce consumption during those periods will receive a rebate for the value of the energy they saved.[32]

The Department anticipates that the on-peak rate will be higher, and the off-peak rate lower than a flat-rate design. Thus, customers who respond to price signals by reducing on-peak energy consumption will pay less than they would under a flat rate. TOU pricing can also be a powerful incentive for the smarter integration of DERs, such as solar PV, that tend to produce the most power during summer months and during peak load hours, thereby reducing peak loads and resulting in both customer and utility savings.

A recent two-year pilot program conducted by the Sacramento Municipal Utility District revealed that customers prefer TOU rates to traditional rate structures. The pilot program tested three TOU options.[33] In one scenario the utility charged an on-peak rate from 4:00 to 7:00 p.m. on weekdays; in another scenario it charged a critical peak rate from 4:00 to 7:00 p.m. on up to 12 days per summer; and in the third scenario it charged both an on-peak rate and critical peak rate. The utility found significant differences in the cost of producing and delivering electricity throughout the day, and also discovered that customers with TOU rates were more satisfied than customers on standard flat rates because customers felt that the TOU rates were fair, provided more opportunity to manage energy costs, and were easier to understand than flat rates.[34]

In 2013, Duke Energy Progress expanded TOU pricing to residential customers as part of a pilot program in its North Carolina service territory. This rate design includes a seasonal, on-peak demand charge, as well as an on-peak and off-peak energy charge. Rates also include a customer charge and rider charges.[35]

TOU pricing can also be used to fairly compensate customers who supply power to the grid. Utilities that make TOU pricing available to net metered solar customers can more accurately compensate such customers for the value of the power they supply to the grid based on when they provide it. TOU pricing can be a powerful incentive for the smarter integration of DERs, such as solar PV, to reduce peak loads and to increase loads when there is surplus solar, resulting in both customer and utility savings. The Hawaii PUC recently issued an Order requiring that the mid-day hours be designated as “off-peak” hours.[36] And the California ISO has proposed TOU pricing that designates peak solar production times as a low-cost period for customers.[37] Under these approaches, the “solar credit” values are tied to on-peak and off-peak demand, and they reduce the potential for lost revenue impacts on the utilities. This TOU approach is an effective alternative to high mandatory fees.[38]

Additionally, Duke Energy Progress is allowing its residential customers to couple its net metering program with its time variant rate options. These options include net metering under “time-of-use,” “time-of-use demand,” and “time-of-use all-energy” schedules.[39] While each option is structured slightly differently, all provide net metered customers with varying levels of compensation based on whether they produce power during peak hours when solar power is more valuable, or during off-peak hours when the value of solar may decrease.[40]

Finally, TOU pricing provides a favorable alternative to **demand charges for residential and small commercial customers**—charges based on a customer’s highest usage every month. Demand charges are unable to account for the diverse usage patterns of residential and small commercial customers, often do not coincide with peak system demand, and can result in significant and inequitable cost-shifting. TOU pricing is a better approach because it more accurately reflects the time-based costs of customer usage and avoids the problems created by such demand charges.

Advanced Metering Infrastructure

Time-of-use rates generally require advanced metering infrastructure (“AMI”) like smart meters. Smart meters allow utilities to receive data, control equipment, and communicate more effectively between the customer and the grid. For example, in 2013, Chattanooga Electric Power Board (“EPB”), a municipal utility served by TVA, completed the installation of smart meters in all homes and businesses in its 600 square mile service area. The meters allow for one billion data points to be collected annually, providing automated meter reading and billing, outage and voltage anomaly detection, automated connect and disconnect and theft detection. Such data help support the use of expanded TOU pricing in EPB’s service area. EPB offers commercial customers a seasonal TOU rate without the need for high fixed charges.[41] Similarly, Memphis Light, Gas and Water (“MLGW”) has recently begun several projects related to smart grid technologies, including the installation of electric, gas and water smart meters at approximately 60,000 homes. MLGW also offers a seasonal TOU rate for residential customers with smart meters.[42]

As the utility industry continues to evolve toward a smarter grid, smart meters will be an essential component of that evolution. Utilities without AMI will likely be unable to keep up with the innovations and opportunities that the changing grid creates. For example, **locational marginal pricing ("LMP")** allows utilities to reflect the value of providing service at different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. There are multiple forms of LMP, with a range of granularity in pricing methods. LMP requires extensive knowledge of the distribution system, customer demand profiles, and the monetization of different energy services in both space and time. LMP is usually applied in wholesale markets, but recently LMP has been proposed with respect to distribution values.[43]

In addition, **attribute pricing** allows utilities to individually account for valuable attributes that may be delivered by customers implementing DERs, or by the utility, such as energy, capacity, reliability, flexibility, resilience, ancillary services and other related value streams. Attribute pricing allows utilities to more accurately compensate or charge customers for the specific value of these services, and it is particularly useful when integrating customer-owned DERs. Attribute pricing is typically paired with TOU pricing which improves its delivery, helping customers make better decisions and giving them appropriate compensation for the services they provide.[44]

AMI allows utilities to collect valuable data and apply that information towards smarter rate design that benefits the utility and its customers. However, even utilities without AMI can choose smarter alternatives to high fixed charges, such as well-designed minimum bills.

Minimum Bills

An increasingly-popular alternative to fixed charges is the adoption of a minimum bill. A well-designed minimum bill guarantees the utility a minimum annual revenue level from each customer, even if their usage is zero, but does not significantly alter the volumetric, per-kWh rate.[45] Unlike a fixed charge, a minimum bill does not come into effect unless the customer uses less than a certain amount of power each month, essentially ensuring utilities that even if no power is consumed, the connection is paid for and that every customer contributes at least a minimum amount toward the maintenance of the grid.

The structure of a minimum bill is crucial to its effectiveness, because a poorly-structured minimum bill can result in similar negative effects as a high fixed charge. The key to minimum bills is to set the minimum at a level that ensures the utility a consistent level of appropriate revenue, while not penalizing the vast majority of customers, or inhibiting efficiency. Minimum bills are determined by calculating the marginal cost to deliver the average daily minimum metered charges per customer. If structured correctly, a minimum bill preserves the incentive to conserve energy by not drastically decreasing the per-kWh energy charge or by shifting the bulk of a bill to a fixed charge, while still providing adequate revenue for the utility.[46] RAP recommends that utilities base minimum bills on the future, marginal cost to deliver energy to each customer, and charge minimum bills annually rather than monthly.[47]

Many utilities throughout the country are exploring the use of minimum bills in lieu of fixed charges. A study by the Texas Ratepayers' Organization to Save Energy documented that the number of Texas retail electricity providers assessing minimum usage fees grew from 36% to 81% between 2011 and 2013.[48] Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric have established residential minimum bill policies. In addition, the Sacramento Municipal Utility District and the Texas Public Utility Commission allow minimum or low usage charges to be assessed on customers with low consumption. The Los Angeles Department of Water and Power imposes a zero fixed charge, a three-block inclining rate design, and a $10 minimum bill.

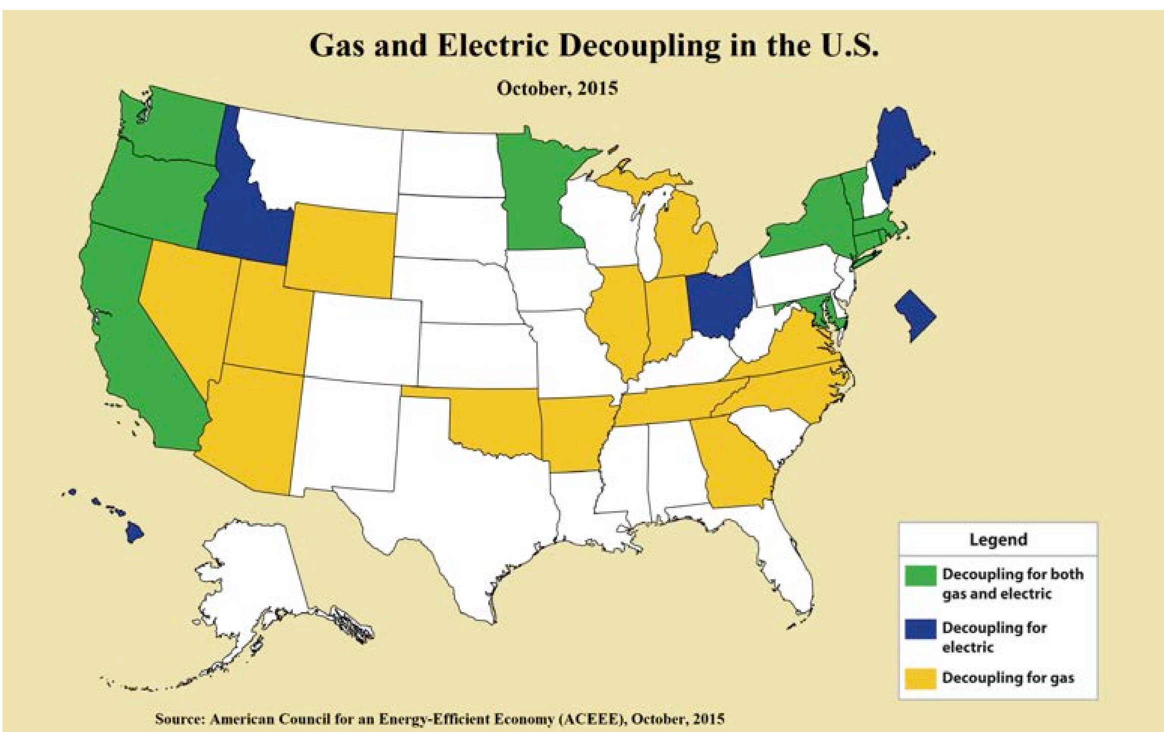
A recent study on the impacts of minimum bills has shown that given a choice between a $20 fixed customer charge with a lower per-kWh rate, and a $20 minimum bill charge with a slightly higher per-kWh rate, customers would consume 15 times as much additional energy under the former as under the latter.[49] Additionally, Greentech Media recently examined the impact of minimum bills on solar customers in comparison to fixed charges and found that a minimum bill would be more economic for solar customers than a fixed charge, assuming the minimum bill is set at the same level as the fixed charge.[50] Greentech Media's study compared the monthly and annual bills of a solar customer with a 6.3 kW rooftop solar system who was charged a $10 monthly minimum bill versus a $10 monthly fixed charge. Under the $10 monthly minimum bill, the solar customer paid less than the customer with the $10 fixed charge.

Revenue Decoupling

One reason utilities are seeking higher mandatory fees is to stabilize their revenue in the face of stagnant or declining sales levels. Another approach to revenue stabilization is known as revenue regulation, or "decoupling." Decoupling is an adjustable rate mechanism that breaks the link between the amount of energy sold and the revenue collected by the utility.[51] Under decoupling, a utility's rates are adjusted every month or every year to account for variations from the sales prediction made when rates were set. If sales decline, rates increase to recover the utility's required revenue. If sales increase, rates decline.

Through decoupling, utilities can achieve revenue stability without changing the rate design in a manner that increases costs to low-income consumers, renters, and other low-use customers. Rates can retain the traditional per-kW recovery of system costs that allocates these costs in proportion to system usage. Customers do not lose the incentive to invest in energy efficiency measures, and the utility becomes indifferent to sales volumes. The utility can concentrate on controlling the cost of service and providing excellent service to consumers.

Decoupling has been used in most U.S. states for electric, gas, and water utilities in one form or another. The map below shows the states in which one or more utilities have implemented some form of revenue regulation mechanism.



Decoupling is usually utilized by investor-owned utilities regulated by a state utilities commission. However, distribution utilities that set their own rates, such as electric cooperatives and municipal utilities, may also implement decoupling as part of their rate design. The Los Angeles Department of Water and Power implemented a decoupling mechanism in 2013. They did so in order to retain a progressive rate design with a zero customer charge and an inclining block rate design, while protecting the revenue stability that ensures the utility's strong bond rating. Since then, decoupling adjustments have been no more than 2% per year.[52]

Decoupling can take several different forms, but all of the methods have a few common elements:

- Initially rates are set in a traditional rate proceeding;
- Rates are adjusted periodically to produce the target revenue, taking into account any increase or decrease in sales volumes compared with the level assumed in the rate proceeding;
- The mechanism is defined in advance as to whether it will cover only distribution costs, or all costs; different methods are appropriate for each approach;
- Some annual cap on how much rates can rise is usually imposed; if sales deviations exceed these thresholds, increases are spread across more than one year;
- A true-up mechanism ensures that the utility recovers the allowed revenue; no more and no less.

CONCLUSION

The electric industry is changing in ways that empower customers but that also may threaten utilities' ability to earn required revenue. Utility customers increasingly have at their disposal a variety of means for reducing their dependence on the grid. As they do this, utilities may be tempted to respond with regressive rate mechanisms, such as high fixed charges. But fixed charges, and other departures from volumetric pricing, are not a good solution. These measures fail to provide a core component of smart rate design, which is to provide accurate pricing signals to customers. Fixed charges hurt low-income customers and encourage economically inefficient outcomes.

Instead of instituting unfair and short-sighted pricing mechanisms, utilities should instead pursue more dynamic, reflective pricing strategies such as time-of-use pricing, well-structured minimum bills, and locational and attribute pricing. Additionally, utilities should consider revenue decoupling to further ensure that necessary revenues are recovered while not deterring efficiency. These pricing strategies respect the customer's right to deploy DERs, while more accurately capturing the benefits and costs to the grid of all resources. This is a better pathway for ensuring utility cost recovery as the grid continues to evolve to meet customer needs and preferences.

There is no one-size-fits-all solution. Each utility and each state is different. In the Southeast, markets are predominantly served by large, vertically integrated utilities. The Southeast also lacks a single regional transmission organization ("RTO") or independent system operator ("ISO") that, in other areas of the country, establishes the methods and economics of real-time transmission costs and contracts for ancillary services. Thus the responsibility falls to the IOUs, electric cooperatives and municipal utilities, and to regulators to create the framework for smarter rate design, to make economically efficient decisions based on the cost of service, and to pursue the innovation necessary to adapt to the changing electricity sector landscape. The pathway may look different in each state, but the goal should be the same: smarter economics and stronger policy that treats customer choice as a resource for the benefit of all ratepayers.

ENDNOTES

[1] Revenue requirements refer to the annual revenues required by the utility to cover both its expenses and have the opportunity to earn a fair rate of return. They also refer to the annual costs to provide safe and reliable service to the company's customers that the company is allowed to recover through rates.

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[3] Jim Lazar, *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs*, Regulatory Assistance Project (2013)(hereinafter "Lazar, Minimum Bills"), http://www.raponline.org/document/download/id/7361.

[4] *Id.*

[5] For the elasticity calculation showing the difference between rate designs, see Jim Lazar, Regulatory Assistance Project, *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed* Appendix A, Regulatory Assistance Project (2013), http://www.raponline.org/document/download/id/6516.

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[7] Deitchman, B., *Beyond Recovery- Policy Options for Energy Efficiency Financing*, World Energy Engineering Congress (October 2014); Baer, Paul, Marilyn A. Brown, and Gyungwon Kim, *The Job Generation Impacts of Expanding Industrial Cogeneration*, 110 Ecological Economics 141-153. (2015); Heidi Garrett-Peltier, *Employment Estimates for Energy Efficiency Retrofits of Commercial Buildings*, Political Economy Research Institute (2011), http://www.peri.umass.edu/236/hash/294809398e497bee9c8abe6ac7df2bdc/publication/466/.

[8] U.S. Energy Information Administration, NERC's Summer Reliability Assessment Highlights Regional Electricity Capacity Margins (2014), https://www.eia.gov/todayinenergy/detail.cfm?id=16791.

[9] U.S. Energy Information Administration, Electricity Data Browser, https://www.eia.gov/electricity/data/browser/; Most analysts attribute this to improved efficiency reducing overall usage, but increased deployment of air conditioning causes higher peak usage.

[10] U.S. Energy Information Administration, Annual Energy Outlook 2015: Projections to 2040 (2015), http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

[11] U.S. Energy Information Administration, Annual Energy Outlook 2015: Energy Consumption by Sector and Source (2015), http://www.eia.gov/beta/aeo/#/?id=2-AEO2015&region=1-6&cases=ref2015&start=2012&end=2040&f=A&linechart=2-AEO2015.3.~2-AEO2015.10.&map=&ctype=linechart.

[12] Tennessee Valley Authority, 2015 Integrated Resource Plan Chapter 4, https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/Documents/2015_irp.pdf.

[13] Rocky Mountain Institute, *The Economics of Grid Defection: When and Where Distributed Solar Generation Plus Storage Competes with Traditional Utility Service* (2014) (hereinafter "Rocky Mountain Institute, *The Economics of Grid Defection*").

[14] State of Nevada Public Utilities Commission, Nevada Net Energy Metering Impacts Evaluation (2014), http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.

[15] Public Service Commission of Mississippi, Net Metering in Mississippi: Costs, Benefits, and Policy Considerations (2014), http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

[16] Maine Public Utilities Commission, Maine Distributed Solar Valuation Study (2015), http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

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[18] Vermont Public Service Department, Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012 (2013), http://www.leg.state.vt.us/reports/2013ExternalReports/285580.pdf.

[19] In 2014, the Colorado Public Utility Commission held workshops on net metering issues; this information was provided for one of these workshops, based on data from solar customers on the Public Service of Colorado system. *See* "On-Site Solar Industry Answer to Questions set forth in Attachment A of Commission Decision No. C14-0776-I," filed July 21, 2014 in Colorado PUC Docket No. 14M-0235E, at pp. 8-9.

[20] Utah PSC, *Order issued* August 29, 2014 in Docket No. 13-035-184, at p. 62.

[21] Deregulation of Electric Utilities, Georges Zaccour (Ed.) (2012); James C. Bonbright, Principles of Public Utility Rates 250-254 (1961); James C. Bonbright, *Fully Distributed Costs in Utility Rate Making*, Amer. Econ. Rev. 305-312 (1961); Jim Lazar and Wilson Gonzalez, *Smart Rate Design for a Smart Future*, Regulatory Assistance Project, (2015), http://raponline.org/document/download/id/7680.

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[23] Cal. Pub. Util. Comm'n, Rulemaking 12-06-013, *Proposed Decision* p. 117 (April 21, 2015).

[24] NVEnergy, Residential Time of Use for Southern Service Territory, https://www.nvenergy.com/home/paymentbilling/timeofuse.cfm.

[25] Chattanooga Electric Power Board, EPB Retail Rate Summary, https://www.epb.net/downloads/power/business/rate-summary.pdf.

[26] Severin Borenstein, *Time-varying Retail Electricity Prices: Theory and Practice*, in Electricity Deregulation: Choices and Challenges (S. L. P. James M. Griffin (Ed.), 2005) (hereinafter "Borenstein, Electricity Deregulation").

[27] Cal. Pub. Util. Comm'n, Rulemaking 12-06-013, *Proposed Decision* p. 117 (April 21, 2015).

[28] Borenstein, Electricity Deregulation.

[29] Massachusetts Department of Public Utilities, Investigation by the Department of Public Utilities Upon its Own Motion into Time Varying Rates (June 12, 2014), http://www.mass.gov/eea/docs/dpu/orders/d-p-u-14-04-b-order-6-12-14.pdf.

[30] Id. The Department noted that in 2013, the average wholesale market price of electricity over the course of the year was $56 per MWh but the peak wholesale price in the summer reached nearly $870 per MWh and in winter nearly $1,300 per MWh.

[31] Under this TOU pricing structure, the retail electricity price will be higher during certain hours of the week when customers typically use more electricity and wholesale energy prices rise (e.g., the "on-peak" hours of noon to 8:00 p.m. each weekday) than during the remaining hours of the week when electricity usage and wholesale prices are typically lower (i.e., the "off-peak" hours).

[32] Under PTR, customers will have an incentive to lower their electricity usage when it is most critical to do so, but even those who ignore the incentive will be insulated against higher peak prices because they will pay one price for all electricity consumption.
[33] The Sacramento Municipal Utility District, which serves approximately 540,000 customers in and around Sacramento, California, implemented a two-year SmartPricing Options pilot program. See Jennifer M. Potter, et. al, Sacramento Municipal Utility District, SmartPricing Options Final Evaluation (Sept. 5, 2014), https://www.smartgrid.gov/files/SMUD-CBS_Final_Evaluation_Submitted_DOE_9_9_2014.pdf.
[34] Jennifer M. Potter, et. al, Sacramento Municipal Utility District, SmartPricing Options Final Evaluation (Sept. 5, 2014), https://www.smartgrid.gov/files/SMUD-CBS_Final_Evaluation_Submitted_DOE_9_9_2014.pdf.
[35] Duke Energy Progress, Time-of-Use Rate R-TOU, http://www.duke-energy.com/tou-dep-residential/default.asp; Duke Energy has had TOU rates for commercial customers in North Carolina since 1975, but the expansion to residential electric TOU rates is new.
[36] Haw. Pub. Util. Comm'n, Docket No. 2014-0192, Decision and Order No. 33258 (Oct. 12, 2015).
[37] California ISO, Matching Time-of-Use Rate Periods with Grid Conditions Maximized Use of Renewable Resources (2015), https://www.caiso.com/Documents/MatchingTimeOfUsePeriodsWithGridConditions-FastFacts.pdf.
[38] Haw. Pub. Util. Comm'n, Docket No. 2014-0192, Decision and Order No. 33258 (Oct. 12, 2015).
[39] Net metering customers under TOU and TOU-E pay a significantly higher price for electricity generated during on-peak hours, but the TOU schedule charges a higher rate for on-peak energy than the TOU-E schedule. The TOU schedule also offers a shoulder rate (between on-peak and off-peak), which provides more opportunity for a customer to avoid on-peak energy consumption, but provides fewer hours for a customer to get paid the maximum on-peak rate for energy generated by their PV system. An advantage of both the TOU and TOU-E rate schedules over the time-of-use demand (TOU-D) schedule is that there is no demand charge. Therefore, a homeowner gets the time-of-use advantage of a higher rate for on-peak PV generation without the burden of a demand charge. The SunSense option pays a lower rate for electricity sold to the grid during both on- and off-peak hours. The greatest advantages of the SunSense program are the reduced upfront cost and the five-year monthly payment based on system size.
[40] North Carolina Solar Center, *A Residential Customer Guide to Going Solar: Duke Energy Progress Versio*n (2014), http://nccleantech.ncsu.edu/wp-content/uploads/Duke-Energy-Progress-Solar-Guide-FINAL-1.pdf.
[41] Chattanooga Electric Power Board, EPB Retail Rate Summary, https://www.epb.net/downloads/power/business/rate-summary.pdf.
[42] Memphis Light Gas & Water, Time-of-Use Residential Rate, http://www.mlgw.com/images/content/files/pdf_rates/RSTOUOct14.PDF.
[43] Recently, the New York Department of Public Service proposed adopting multiple changes in rate design for their delivery rates, including the adoption of LMP with the added marginal value of distribution. This is different from, DLMP, which is sometimes used to refer to a granular calculation of time- and location-specific costs on the distribution system. LMP+D is a broader measure capturing the full value of DER, including energy (LMP) and the full range of values provided by distribution level resources (D). *See* New York State Energy Research and Development Authority, *Large-Scale Renewable Energy Development in New York: Options and Assessments* (2015), filed in N.Y. Pub. Serv. Comm'n. Docket No. 15-E-0302 (June 1, 2015).
[44] Rocky Mountain Institute, *The Economics of Grid Defection*.
[45] Jim Lazar, Regulatory Assistance Project, Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs (2013)(hereinafter "Lazar, Minimum Bills"), http://www.raponline.org/document/download/id/7361.
[46] Jim Lazar, *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed 26*, Regulatory Assistance Project (2013); Lazar, Minimum Bills.
[47] Lazar, Minimum Bills.
[48] Carol Biedrzycki, *Texas Ratepayers' Organization to Save Energy, Texas Electric Consumers, Beware of REP Fees* (2013), http://texasrose.org/wp-content/uploads/2013/08/Fees-Summary-2013-Report-by-Texas-ROSE.pdf.
[49] Lazar, Minimum Bills.
[50] Josh Cornfeld & Shayle Kahn, *Why a Minimum Bill May be a Solution to Net Metering Battles*, Greentech Media (July 24, 2014), http://www.greentechmedia.com/articles/read/why-the-massachusetts-net-metering-compromise-could-be-a-model-for-other-st.
[51] Jim Lazar et al., *Revenue Regulation and Decoupling: A Guide to Theory and Application* 1, Regulatory Assistance Project (2011).
[52] Los Angeles Department of Water and Power, Residential Adjustment Billing Factors, https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-financesandreports/a-fr-electricrates/a-fr-er-energycostadjustmentfactor?_adf.ctrl-state=1b62srqg5m_4&OwnesLake&&_afrLoop=375353535571103; Los Angeles Department of Water and Power, Commercial Adjustment Billing Factors, https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-financesandreports/a-fr-electricrates/a-fr-er-energysubsidyadjustmentfactor?_adf.ctrl-state=1b62srqg5m_4&OwnesLake&&_afrLoop=375589380925260.

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An Econometric Assessment of Electricity Demand in the United States Using Panel Data and the Impact of Retail Competition on Prices

By **Dr. Agustin J. Ros**

This paper was originally presented at the Rutgers University Center for Research in Regulated Industries, 34th Annual Eastern Conference.

Introduction

Since the early 1970s electricity demand in the United States has been growing at an average annual rate of approximately 2%. In that period there have been major developments in the electricity sector including significant technological changes in generation services and the development of wholesale and retail competition. In this paper I use panel data covering 72 electricity distribution companies in the United States during the period from 1972–2009 to econometrically estimate structural demand equations separately for residential, commercial, and industrial customers and to examine the impact that retail competition has had on electricity prices.

I find the own-price elasticity of demand for residential, commercial, and industrial consumers that are generally consistent with the published economics literature, ranging between -0.382 and -0.613 for residential demand, -0.747 for commercial demand, and ranging between -0.522 and -0.868 for industrial demand. Regarding retail electricity competition, I econometrically examine the impact of the restructuring of the retail electricity sector in the US from the mid-1990s. Since this period and up to 2009, a total of 21 states permitted retail customers (some states permitting only large industrial customers and some states also permitting smaller commercial and residential customers) to select their electricity generation supplier (retail competition) from a firm other than the incumbent electricity distribution company. As of 2009, 17 and 15 states still permitted retail competition for large and smaller customers, respectively. I estimate reduced-form static and dynamic price equations controlling for demand and supply factors, and include a binary variable for those states and time periods where retail competition was permitted. I test the null hypothesis that retail competition had no statistically significant impact on real electricity prices. I find that retail electricity competition is associated with lower electricity prices for each customer class with the magnitude of the impact being greater for the larger customer classes.

Literature Review

There is a large economic literature on electricity demand in the US and other countries. Using data on US residential electricity demand for 1949–1993, Silk and Joutz (1997) find that a 1% increase in electricity prices reduces electricity consumption by -0.62%. With respect to disposable income, they find a 1% increase in income leads to a 0.82% increase in electricity consumption. Using data on residential demand for electricity in the US, Dergiades and Tsoulfidis (2008) find short- and long-run price elasticities of demand to be -0.386% and -1.065%, respectively. With regard to income, they find short- and long-run income elasticities of demand to be 0.101% and 0.273%, respectively. Paul, Myers, and Palmer (2009) find US short-run price elasticities of demand ranging between -0.04 and -0.32 (depending on customer class and region of the country), and long-run price elasticities of demand ranging between -0.02 and -1.15 (depending on customer class and region of the country). In the same paper, they summarize the results from previous studies, which I summarize below in Table 1.

Table 1. **Summary of Own-Price Elasticities of Demand from the Literature**

Customer Class	Reference	Short Run	Long Run
Residential	Bohi and Zimmerman (1984) (consensus)	-0.2	-0.7
	Dahl and Roman (2004)	-0.23	-0.43
	Supawat (2000)	-0.21	-0.98
	Espey and Espey (2004)	-0.35	-0.85
	Bernstein and Griffin (2005)	-0.24	-0.32
Commercial	Bohi and Zimmerman (1984)	0	-0.26
	Bernstein and Griffin (2005)	-0.21	-0.97
Industrial	Bohi and Zimmerman (1984)	-0.11	-3.26
	Dahl and Roman (2004)	-0.14	-0.56
	Taylor (1977)	-0.22	-1.63
All	Dahl and Roman (2004)	-0.14	-0.32

Source: Paul, Myers and Palmer (2009), Table 5

Finally, using data from the Korean service sector, Lim and Lim (2014) find the short- and long-run price elasticities of electricity demand to be -0.421 and -1.002, respectively, and find short- and long-run income elasticities of electricity demand to be 0.855 and 1.090, respectively.

With regard to the impact of electricity competition, a number of studies are focused on the wholesale sector but few studies focus on the retail sector. Regarding the former, Kleit and Terrell (2001) find that by eliminating technical inefficiencies, gas-fired generation plant could reduce costs by up to 13%. Fabrizio *et al.* (2007) found evidence of reduced fuel and nonfuel expenses in fossil-fueled plants in states that restructured their wholesale markets. Zhang (2007) finds that, in states that have restructured nuclear-fueled plants, utilization is higher and operating costs are lower.

Regarding the impact of retail competition, a recent paper by Su (2014) uses a difference-in-difference approach to estimate the policy impact for US states that restructured their electricity retail markets. Su finds that "only residential customers have benefitted from significantly lower prices but not commercial or industrial customers. Furthermore, this benefit is transitory and disappears in the long run." Swadley and Yücel (2011) find that retail competition makes the market more efficient by lowering the markup of retail prices over wholesale costs, and it generally appears to lower prices in states with higher customer participation rates in retail choice.

Data

I use several different data sources for my study: (I) FERC Form 1 data that contains information on residential, commercial, and industrial revenues and sales volume; (II) data from the bureau of labor statistics on price indices used for deflating prices and other relevant variables; and (III) inputs and results from a total factor productivity study containing information on cost indices, and total factor productivity for the 72 US electricity firms that I use in this study.[1] In Table 2 below, I provide a description of the variables and data sources used for this study using average revenue per unit as a proxy for price.[2]

Table 2. **Description of Variables**

Variable Name	Description	Data Source
Lntfp	Natural log of index of total factor productivity	*TFP Study*
ln_rpres	Natural log of deflated residential revenue per unit sales volume using US census region cpi and urban consumer as deflator	FERC Form 1, *TFP Study,* and author's calculations
ln_rpcom	Natural log of deflated commercial revenue per unit sales volume using US census region cpi and urban consumer as deflator	FERC Form 1, *TFP Study,* and author's calculations
ln_rpindus	Natural log of deflated industrial revenue per unit sales volume using US census region cpi and urban consumer as deflator	FERC Form 1, *TFP Study,* and author's calculations
ln_qres	Natural log of residential sales volume	FERC Form 1, *TFP Study,* and author's calculations
ln_qcom	Natural log of commercial sales volume	FERC Form 1, *TFP Study,* and author's calculations
ln_qindus	Natural log of industrial sales volume	FERC Form 1, *TFP Study,* and author's calculations
labprcindex	Real labor cost index	FERC Form 1 and *TFP Study*
caprcindex	Real capital cost index	FERC Form 1 and *TFP Study*
t_hdd	State heating degree day index	National Oceanic and Atmospheric Administration
t_cdd	State cooling degree day index	National Oceanic and Atmospheric Administration
ln_pop	Natural log of state population	Bureau of Economic Analysis
ln_income	Natural log of real state personal income using US census region cpi and urban consumer as deflator	Bureau of Economic Analysis
ln_price_natural gas	Natural log of real state natural gas price index using US census region cpi and urban consumer as deflator	US Energy Information Administration
compl	Indicator variable 1 if competition for large industrial customers is permitted	Author's construct
comps	Indicator variable 1 if competition for residential and commercial customers is permitted	Author's construct
ratecap	Indicator variable 1 if state that permitted competition had a rate cap for residential and commercial customers	Swadley and Yücel (2011) Table 1

In Table 3 below, I present summary statistics of the variables. Mean values over the period for deflated residential, commercial, and industry prices were ¢10.02 kWh, ¢8.91 kWh, and ¢6.16 kWh, respectively. And over the time period, there was a downward trend in deflated prices for all customer classes beginning in the late 1980s and lasting through the early 2000s. Approximately 14% and 13% of observations of the data reflect retail competition for large and residential and commercial customers, respectively.

Table 3. **Summary Statistics**

Variable	Obs	Mean	Std. Dev.	Min	Max
lntfp	2736	.5056051	.3717154	-.8342119	1.662097
unem	2448	6.16156	2.008683	2.3	15.6
ln_pop	2736	15.59572	.9018602	13.04594	17.42538
ln_rpres	2736	-2.300279	.2935026	-3.328425	-1.22254
ln_rpcom	2736	-2.417624	.3220173	-3.37734	-1.371787
ln_rpindus	2697	-2.786458	.3775694	-4.643488	-1.363757
ln_qres	2736	15.19656	.9528475	12.62801	17.82536
ln_qcom	2736	15.03261	1.052372	11.754	17.66853
ln_qindus	2736	15.02367	1.051302	11.01396	17.18522
labprcindex	2736	.8858641	.2957938	.2484632	3.048455
caprcindex	2736	1.148668	.5397295	.2104876	11.42236
t_hdd	2736	5162.852	2064.818	430	10810
t_cdd	2736	1100.366	862.2685	74	3827
ln_income	2736	10.1229	.2125993	9.519778	10.71989
ln_price_natural gas	2367	2.091865	.1812828	1.358819	2.655835
Compl	2736	.1425439	.349671	0	1
Comps	2736	.1312135	.3376954	0	1
Rate cap	2736	.0811404	.2731004	0	1

Econometric Models

Econometric estimation of US electricity demand

I estimate demand equations for US electricity distribution services for a 72-company panel sample from 1972 to 2009 to determine the price elasticity of demand, as well as the effects of other factors. I estimate demand equations separately for residential, commercial, and industrial electricity demand. In these demand equations, output (sales volume) is the left-hand side dependent variable. I am measuring how electricity output changes when other variables, such as price and income, change. The basic model is of the form:

(1) $y_{it} = \boldsymbol{Y}_{it}\,\gamma + \boldsymbol{X}_{it}\beta + \mu_i + \upsilon_{it}$

Where y_{it} is the dependent variable (electricity consumption), $\boldsymbol{Y}_{it}$ is a 1 x g_2 vector of observations on g_2 endogenous variables included as covariates (in my demand models, g_2 =1 since I assume that price is the only endogenous variables), and these variables are allowed to be correlated with the υ_{it}, $\boldsymbol{X}_{it}$ is a 1 x k_1 vector of observations on the exogenous variables included as covariates (such as income, population, price of natural gas, and heating and cooling degree days), γ is a g_2 x 1 vector of coefficients, β is a k_1 x 1 vector of coefficients, μ_i is the individual-level effect (i.e., the unobservable company-level effects), and υ_{it} is the disturbance term.

I estimate demand models for each type of customer using four different estimators: fixed-effects, random-effects, first-difference, and the Arellano-Bond estimator for dynamic models. The fixed-effect estimator fits the model after sweeping out the μ_i by removing the panel-level means from each variable. The random-effects estimator treats the μ_i as random variables that are independent and identically distributed (*i.i.d.*) over the panels. The first-difference estimator removes the μ_i by fitting the model in first differences. The Arellano-Bond model is a linear dynamic panel-data model that includes *p* lags of the dependent variables as covariates and contains unobserved panel-level effects, fixed or random.[3]

I expect price to be endogenous, and for instruments I use data from the *TFP Study* of US distribution companies. Specifically, I use a deflated labor price index and a deflated capital price index. These two variables reflect changes in input costs for the 72 distribution companies over the period and are thus good candidates for instruments. In addition to price, I expect electricity demand to be positively related to population, real income, the state heating degree day index, the state cooling degree day index, and the deflated price of natural gas.[4] To capture the possibility of changing demand preferences over time, I include three decade binary variables.

Residential demand models

The first three models are static demand models, while the Arellano-Bond model is a dynamic demand model. Table 4 contains the results of my static and dynamic residential demand equations. Since the left-hand side dependent variable is the log of residential demand, the coefficient on residential prices is the price elasticity of demand. The fixed-effects and random-effects estimators provide very similar results for the price elasticity of demand and for all the variables in the model. The price elasticity of demand using the fixed-effects estimator is estimated to be -0.440 and statistically significant (*t* statistic = -3.65). The price elasticity of demand using the random-effects estimator is estimated to be -0.430 and statistically significant (*t* statistic = -3.57). When I use the first-difference estimator, the price elasticity of demand increases to -0.613 (*t* statistic = -3.23). Finally, when I use the Arellano-Bond dynamic estimator, the price elasticity of demand is estimated to be -0.382, and is estimated very precisely.[5] The econometric evidence, therefore, supports a price elasticity of demand for residential customers ranging between -0.382 and -0.613.[6] These estimates are within the range found in the economic literature (see Section 2 above).

With respect to the income elasticity of demand, the fixed-effects and random-effects estimators also provide very similar results. The income elasticity of demand using the fixed-effects estimator is estimated to be 0.366 and statistically significant (*t* statistic = 5.51). The income elasticity of demand using the random-effects estimator is estimated to be 0.372 and statistically significant (*t* statistic = 5.64). When I use the first-difference estimator, the income elasticity of demand decreases to 0.105 (*t* statistic = 1.90). Finally, when I use the Arellano-Bond dynamic estimator, the income elasticity of demand is estimated to be 0.411 and is estimated very precisely.

To control for changes in quantity demanded over time, I included three decade binary variables. All the decade variables are positive and statistically significant. Specifically, using the results from the fixed-effects estimator I find that, compared to the 1970s and holding all factors constant, residential demand in the 1980s, 1990s, and 2000s was approximately 10%, 12%, and 13% higher, respectively. The similarity in the coefficients suggests that, holding all factors in the model constant, residential demand has not changed much since 1980.

Other variables in the model are population, the price of natural gas, and the heating and cooling degree day indices. With respect to population, the four models provide similar results: a 1% increase in population results in an increase in residential demand ranging between 0.786% and 0.873% and is estimated very precisely (in each case a p-value of less than 0.001). I find natural gas to be a substitute for residential electricity consumption. A 1% increase in the real price of natural gas results in an increase in residential electricity consumption of approximately 0.090%. Finally, I find that the heating and cooling degree days index positively affects the demand for residential electricity.

Table 4. **Estimation of Static 2SLS and Dynamic Residential Demand Equations Using Panel Data**

Variable	Fixed Effects	Random Effects	First Difference	Arellano-Bond
ln_rpres	-.43983922***	-.42958065***		-.10504817***
decade_80s	.09833813***	.09856919***		.01954227***
decade_90s	.11720025***	.12003327***		.02868456***
decade_2000s	.12444248***	.12918732***		.02141042**
ln_pop	.87328382***	.85569493***		.21840973***
t_hdd	.00003234***	.00003248***		.00002846***
t_cdd	.00011367***	.00011673***		.00017076***
ln_income	.36623779***	.37236283***		.11290548***
ln_price natural gas	.08934869***	.09028773***		.00541858
ln_rpres_cpi D1.			-.61326955**	
decade_80s D1.			.0111662	
decade_90s D1.			.0131513	
decade_2000s D1.			.01895704	
ln_pop D1.			.78628219***	
t_hdd D1.			.00003095***	
t_cdd D1.			.00013223***	
ln_income D1.			.10526433	
ln_price natural gas D1.			.02681842	
ln_qres L1.				.72511645***
_cons	-3.6963764***	-3.4667861***	.00727446***	-.95904616***
N	2367	2367	2295	2295
Wald χ^2	Prob > χ^2 0.0000	Prob > χ^2 0.0000	Prob > χ^2 0.0000	Prob > χ^2 0.0000

*p<0.05; **p<0.01; ***p<0.001

Commercial demand models

Table 5 contains the results of my static and dynamic commercial demand equations. The fixed-effects and random-effects estimators provide very similar results for the price elasticity of demand and for all the variables in the model. The price elasticity of demand using the fixed-effects estimator is estimated to be -0.427 but is not estimated precisely (*t* statistic = -1.71). The price elasticity of demand using the random-effects estimator is estimated to be -0.423 and is also not statistically significant (*t* statistic = -1.71). When I use the first-difference estimator, the price elasticity of demand decreases to -0.084 but is estimated with very poor precision (*t* statistic = -0.39). Finally, when I use the Arellano-Bond dynamic estimator, the price elasticity of demand is -0.747 and estimated very precisely.[7] The econometric evidence, therefore, supports a price elasticity of demand for commercial customers of -0.747, also within the findings in the economics literature (see Section 2).

With respect to the income elasticity of demand, the fixed-effects and random-effects estimators also provide very similar results. The income elasticity of demand using the fixed-effects estimator is estimated to be 0.877 and statistically significant (*t* statistic = 3.90). The income elasticity of demand using the random-effects estimator is estimated to be 0.883 and statistically significant (*t* statistic = 3.98). When I use the first-difference estimator, the income elasticity of demand decreases to 0.448 (*t* statistic = 4.98). Finally, when I use the Arellano-Bond dynamic estimator, the income elasticity of demand is estimated to be 0.584 and is estimated very precisely. The econometric evidence thus supports an income elasticity of residential electricity demand ranging between 0.448 and 0.883. These estimates are within the range found in the economic literature (see Section 2).

To control for changes in quantity demanded over time, I included three decade binary variables. All the decade variables are positive and statistically significant. Specifically, using the results from the fixed-effects estimator I find that, compared to the 1970s and holding all factors constant, commercial demand in the 1980s, 1990s, and 2000s was approximately 14%, 23%, and 20% higher, respectively.

Other variables in the model are population, the price of natural gas, and the heating and cooling degree day indices. With respect to population, a 1% increase in population results in an increase in commercial demand ranging between 0.472% and 0.767%, depending on the model, and is estimated precisely, in three cases with a p-value of less than 0.001. I find evidence that natural gas is a substitute for commercial electricity demand in two of the four models, with a 1% increase in the real price of natural gas resulting in approximately a 0.10% increase in commercial demand. And I find some evidence that the heating and cooling degree days index positively impacts the demand for commercial electricity.

Table 5. **Estimation of Static 2SLS and Dynamic Commercial Demand Equations Using Panel Data**

Variable	Fixed Effects	Random Effects	First Difference	Arellano-Bond
ln_rpcom_cpi	-.42668522	-.42263656		-.11108075***
decade_80s	.13077288***	.13085258***		.02271251**
decade_90s	.20658202***	.20768634***		.02041106*
decade_2000s	.1796107**	.18139979**		-.01235798
ln_pop	.66475958***	.65881121***		.11411259***
t_hdd	4.084e-06	3.800e-06		9.531e-06
t_cdd	1.707e-06	2.974e-06		.00008662***
ln_income	.87698091***	.8803502***		.08685953**
ln_price natural gas	.09677514*	.09694503*		-.00966809
ln_rpcom_cpi D1.			-.08351428	
decade_80s D1.			.00950299	
decade_90s D1.			.02985924	
decade_2000s D1.			.04058238*	
ln_pop D1.			.47245619*	
t_hdd D1.			.00001042*	
t_cdd D1.			.00006827***	
ln_income D1.			.44778965***	
ln_price natural gas D1.			-.01570014	
ln_qcom L1.				.85125672***
_cons	-5.5837047***	-5.5164864***	.0167317***	-.7947528
N	2367	2367	2295	2295
Wald χ^2	Prob > χ^2 0.0000	Prob > χ^2 0.0000	Prob > χ^2 0.0000	Prob > χ^2 0.0000

*p<0.05; **p<0.01; ***p<0.001

Industrial demand models

Table 6 contains the results of my static and dynamic industrial demand equations. The price elasticity of demand using the fixed- and random-effects estimator is contrary to economic theory, showing a positive price elasticity of demand. I therefore rely on the results from the first-difference and Arellano-Bond models. When I use the first-difference estimator, I find the price elasticity of demand to be -0.868 (*t* statistic = -2.80). When I utilize the Arellano-Bond dynamic estimator, the price elasticity of demand is estimated to be -0.522 and is estimated precisely.[8] The econometric evidence, therefore, supports a price elasticity of demand for industrial customers between -0.522 and -0.868, also within the findings in the economics literature (see Section 2).

With respect to the income elasticity of demand, the fixed-effects and random-effects estimators also provide very similar results. The income elasticity of demand using the fixed-effects estimator is estimated to be 1.467 and statistically significant (*t* statistic = 4.95). The income elasticity of demand using the random-effects estimator is estimated to be 1.456 and statistically significant (*t* statistic = 5.02). The income elasticity of demand using the first-difference estimator is significantly lower at 0.720 (with a student *t* statistic = 4.26). When I use the Arellano-Bond dynamic estimator, the income elasticity of demand is estimated to be 1.58 and is estimated precisely and closer to the estimates found from the fixed- and random-effects estimators.

To control for changes in quantity demanded over time, I included three decade binary variables. The results are mixed. Three of the four models suggest that industrial electricity demand was lower in the 1980s (than in the 1970s) but higher in the 1990s and 2000s. The remaining model, however, suggests that industrial electricity demand was lower in each decade compared to the 1970s.

Other variables in the model are population, the price of natural gas, and the heating and cooling degree day indices. With respect to population, the fixed and random effects model finds that a 1% increase in population results in an increase in industrial demand of 0.361% and 0.338%, respectively while for the first-difference model a 1% increase in population results in an increase in industrial demand range of 0.882%. I find evidence in the Arellano-Bond model that natural gas is a complement for industrial electricity consumption. A 1% increase in the real price of natural gas results in a decrease in industrial electricity consumption of approximately 1.236%. Finally, I do not find strong evidence that the heating and cooling degree days index impacts the demand for industrial electricity.

Table 6. **Estimation of static 2SLS and dynamic industrial demand equations using panel data**

Variable	Fixed Effects	Random Effects	First Difference	Arellano-Bond
ln_rpindus_cpi	1.1752322***	1.1937324***		-.0342152*
decade_80s	-.11297932**	-.11340149**		-.03659619***
decade_90s	.13545005**	.14296852**		-.06222053***
decade_2000s	.07849822	.0928366		-.12470984***
ln_pop	.36146288**	.33779817**		.06730164
t_hdd	-7.977e-06	-.00001413		-8.382e-06
t_cdd	.00003866	.0000471		2.600e-06
ln_income	1.4671618***	1.4585598***		.10344492*
ln_price natural gas	.13354912	.12156241		-.08090781*
ln_rpindus_cpi D1.			-.86765614**	
decade_80s D1.			.06215827**	
decade_90s D1.			.06364113*	
decade_2000s D1.			.07172708*	
ln_pop D1.			.8819554**	
t_hdd D1.			-2.597e-06	
t_cdd D1.			-.0000136	
ln_income D1.			.71977543***	
ln_price natural gas D1.			-.02696871	
ln_qindus L1.				.93404923***
_cons	-2.5161967	-1.9718117	-.03033039***	-.92398406
N	2333	2333	2262	2262
Wald χ^2	Prob > χ^2 0.0000	Prob > χ^2 0.0000	Prob > χ^2 0.0000	Prob > χ^2 0.0000

*p<0.05; **p<0.01; ***p<0.001

Econometric Estimation of US Electricity Price Equations

In this section, I estimate reduced-form price equations for residential, commercial, and electricity customer classes. The left-hand side dependent variable is log of real price and is the same price variable that I used above for the demand equations. The right-hand side independent variable *comps* is a binary variable with a value of one if the state permitted retail competition for residential and commercial (small) customers. I use this variable for the residential and commercial price equations. For the industrial price equations, the variable *compl* is a binary variable with a value of one if the state permitted retail competition for industrial (large) consumers.

I estimate fixed and random effects models assuming that *comps* and *compl* are exogenous. In addition, I again estimate dynamic models using the Arellano-Bond estimator and provide two results: the first treats the competition variable as exogenous, and the second assumes it is endogenous and uses the lagged values of the competition variable as instruments.

Other independent variables in my reduced-form price equation include binary variables for the 1980s, 1990s, and 2000s, log of population, log of the firm's total factor productivity (*lntfp*), heating and cooling degree day indices, real personal income, and the log of real price of natural gas. I also include the variable *ratecap* to control for the fact that some of the states that permitted competition imposed a rate cap on electricity prices for small customers (residential and commercial) for a period of time. Thus, it is important to control for this effect, otherwise the effect would be included within the *comps* coefficient. The variable *ratecap* is a binary variable with one in those states that permitted competition and had a rate cap in the year in question.

Residential price equations

Table 7 contains the results of my residential price model. The fixed and random effects estimators provide very similar results (and each having a p-value of less than 0.001): holding all other factors constant, residential prices were approximately 8% *lower* in those states that permitted retail competition for residential and commercial consumers. The Arellano-Bond estimator—assuming that *comps* is exogenous (model 3)—indicates that residential prices were approximately 3% *lower* in those states that permitted retail competition for residential and commercial consumers, but the effect was not significant. When I use the Arellano-Bond estimator and consider comps as endogenous, I find the impact is practically zero and is not estimated precisely. Based upon these results, while there is some evidence that residential electricity competition is associated with lower residential prices, additional work should be performed on finding suitable instruments for the *comps* variable in order to ensure that the parameter estimates for *comps* are unbiased.

Other significant findings include the impact of *lntfp* and personal income on residential electricity prices. In each of the models, an increase in tfp of 1% results in a decrease in residential prices, ranging from -0.253% to -0.084%. In each of the models, an increase in personal income results in a decrease in prices, ranging from -0.338% to -0.186%.

Table 7. **Estimation of Static and Dynamic Residential Price Equations Using Panel Data**

Variable	Fixed Effects (1)	Random Effects (2)	Arellano-Bond (3)	Arellano-Bond (4)
comps	-.089***	-.084***	-.008	-.001
ratecap	-.105***	-.101***	-.085***	-.081***
decade_80s	.045***	.043***	.02***	.02***
decade_90s	-.057***	-.065***	.009	.009
decade_2000s	-.075***	-.098***	.06***	.056***
ln_pop	.053	.067***	-.016	.007
Lntfp	-.22***	-.253***	-.087***	-.084***
t_hdd	-2.2e-05*	-1.2e-05*	-6.78e-06	-6.67e-06
t_cdd	-4.3e-05***	-5.2e-05***	-2.15e-05*	-2.5e-05*
ln_income	-.338***	-.258***	-.186***	-.191***
ln_price natural gas	-.079***	-.048	.042*	.045*
ln_rpres_cpi L1.			.773***	.780***
_cons	.792	.330	1.61**	1.53**
N	2367	2367	2295	2295

*p<0.05; **p<0.01; ***p<0.001

Commercial price equations

Table 8 contains the results of my commercial price model. The fixed- and random-effects estimators provide very similar results (each having a p-value of less than 0.001): holding all other factors constant, commercial prices were approximately 16% lower in those states that permitted retail competition for residential and commercial consumers. The Arellano-Bond estimator, assuming that *comps* is exogenous (model 3), indicates that commercial prices were approximately 19% lower in those states that permitted retail competition for residential and commercial consumers (with a p-value of less than 0.001). When I use the Arellano-Bond estimator and consider *comps* as endogenous, the impact is approximately 19%. Based upon these results, there is evidence that commercial electricity competition is associated with lower commercial prices.

Other significant findings include the impact of *lntfp* and personal income on residential electricity prices. In each of the models, an increase in tfp results in a decrease in prices, ranging from -0.278% to -0.056%. In each of the models, an increase in personal income results in a decrease in prices, ranging from -0.68% to -0.29%.

Table 8. **Estimation of Static and Dynamic Commercial Price Equations Using Panel Data**

Variable	Fixed Effects (1)	Random Effects (2)	Arellano-Bond (3)	Arellano-Bond (4)
comps	-.176***	-.171***	-.038***	-.035***
ratecap	-.014	-.010*	-.019	-.011
decade_80s	.019	.016	.0042	.004
decade_90s	-.108***	-.119***	-.008	-.007
decade_2000s	-.105***	-.134***	.051***	.05***
ln_pop	.075*	.079***	.027	.027
lntfp	-.236***	-.278***	-.058***	-.056**
t_hdd	-2.5e-05**	-1.0e-05	-5.7e-06	-5.3e-06
t_cdd	-3.2e-05	-4.7e-05*	-2.2e-05	-2.3e-05
ln_income	-.683***	-.567***	-.296***	-.292***
ln_price natural gas	-.087**	-.048	.049	.057*
ln_rpcom_cpi L1.			.811***	.821***
_cons	3.89***	2.55***	2.09***	2.06***
N	2367	2367	2295	2295

*p<0.05; **p<0.01; ***p<0.001

Table 9 contains the results of my industrial price model. The fixed- and random-effects estimators provide very similar results (each having a p-value of less than 0.001): holding all other factors constant, industrial prices were approximately 24% lower in those states that permitted retail competition for industrial consumers. The Arellano-Bond estimator indicates that industrial prices were approximately 30% lower in those states that permitted retail competition for industrial consumers (with a p-value of less than 0.001). When I use the Arellano-Bond estimator and consider *compl* as endogenous, the impact is approximately 29%. Based upon these results, there is evidence that industrial electricity competition is associated with lower industrial prices.

Other significant findings include the impact of tfp and personal income on residential electricity prices. In each of the models, an increase in tfp results in a decrease in prices, ranging from -0.263% to -0.067%. In each of the models, an increase in personal income results in a decrease in prices, ranging from -0.811% to -0.376%.

Table 9. **Estimation of Static and Dynamic Industrial Price Equations Using Panel Data**

Variable	Fixed Effects (1)	Random Effects (2)	Arellano-Bond (5)	Arellano-Bond (6)
Compl	-.269***	-.263***	-.0741***	-.0674***
decade_80s	.0861***	.0844***	.00935	.00762
decade_90s	-.0779***	-.0866***	-.00336	-.00385
decade_2000s	-.0404	-.0715*	.0813***	.0799***
ln_pop	.175***	.0967***	-.00951	-.00845
Lntfp	-.193***	-.263***	-.075**	-.0674**
t_hdd	-3.0e-05*	-8.8e-06	-3.4e-06	-3.7e-06
t_cdd	-4.5e-05	-5.1e-05*	-1.1e-05	-1.3e-05
ln_income	-.811***	-.616***	-.379***	-.376***
ln_price natural gas	-.149***	-.0795	.0317	.0377
ln_rpindus_cpi L1.			.791***	.803***
_cons	3.38***	2.44***	3.39***	3.37***
N	2333	2333	2262	2262

*p<0.05; **p<0.01; ***p<0.001

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Notes

1 I was the co-author (with Jeff Makholm) of an expert report entitled *Total Factor Productivity in the United States Electricity Sector from 1972–2009*. We were expert witnesses on behalf of the Alberta Public Utility Commission in a proceeding in 2012 whose objective was setting tariffs for electricity and gas distribution companies. Our analysis was used to establish the X-factor in a price cap plan. Throughout this paper, I refer to the study as "*TFP Study*."

2 I did not have data on actual tariffs for the different customer classes over the time period. Instead, I use average revenue per unit as a proxy for price and assume that some errors exist in variable (EIV). Nevertheless, EIV should not present a significant problem because I treat the price variable as (jointly) endogenous in my structural demand equations, and I explicitly model price in my reduced-form price equations.

3 The model is constructed so that by definition the unobserved panel-level effects are correlated with the lagged dependent variables, thus making standard estimators inconsistent. Arellano and Bond derived a consistent generalized method-of-moments (GMM) estimator for the parameters of the model.

4 I consider natural gas as a substitute for electricity and expect the cross-price elasticity of demand to be positive.

5 The total effect is -.105048/(1-.725116).

6 I also estimate every model by including interaction terms between the price variable and each decade variable to test whether there is evidence that the price elasticity of residential electricity demand changed significantly during the decades. For the fixed-effects model, the price elasticity of demand for the 1980s, 1990s, and 2000s ranged between -0.383 to -0.474, similar to the models without the interaction effects but the parameters were not estimated precisely, none being significant at the 5% level of statistical significance. Results for the random-effects estimator are similar.

7 The total effect is -.11108075/(1-.85125672).

8 The total effect is -.0342152/(1-.93404923).

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DISCUSSION PAPER

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A Partial Adjustment Model of U.S. Electricity Demand by Region, Season, and Sector

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RESOURCES FOR THE FUTURE

A Partial Adjustment Model of U.S. Electricity Demand by Region, Season, and Sector

Anthony Paul, Erica Myers, and Karen Palmer

Abstract

Identifying the factors that influence electricity demand in the continental United States and mathematically characterizing them are important for developing electricity consumption projections. The price elasticity of demand is especially important, since the electricity price effects of policy implementation can be substantial and the demand response to policy-induced changes in prices can significantly affect the cost of policy compliance. This paper estimates electricity demand functions with particular attention paid to the demand stickiness that is imposed by the capital-intensive nature of electricity consumption and to regional, seasonal, and sectoral variation. The analysis uses a partial adjustment model of electricity demand that is estimated in a fixed-effects OLS framework. This model formulation allows for the price elasticity to be expressed in both its short-run and long-run forms. Price elasticities are found to be broadly consistent with the existing literature, but with important regional, seasonal, and sectoral differences.

Key Words: electricity, demand elasticities, energy demand, partial adjustment

JEL Classification Numbers: L94

Contents

A Partial Adjustment Model of U.S. Electricity Demand by Region, Season, and Sector

Anthony Paul, Erica Myers, and Karen Palmer*

Introduction

The electricity sector in the United States is large and growing, accounting in 2007 for 2.6 percent of U.S. GDP and just over 40 percent of total U.S. energy consumption (U.S. EIA 2008b). Electricity consumption has nearly doubled in the past 30 years (U.S. EIA 2008b), and the Energy Information Administration (EIA) forecasts another 23 percent increase over the next two decades under business-as-usual conditions (U.S. EIA 2008a). Identifying the factors that influence electricity demand and mathematically characterizing them are important for developing such electricity consumption projections, and reliable projections are important for policymakers.

The institutions governing how electricity prices are set vary across the nation; nonetheless, changes in policy can affect prices under any regime, and the demand response to changing prices is important to both economic and environmental policy analysis. As an example, a federal climate change policy in the United States has the potential to substantially affect electricity prices. Ignoring the price responsiveness of consumers in projecting a climate policy outcome could lead to an overestimate of costs. Climate policy is only one of myriad federal-, regional-, and state-level policy proposals that could affect electricity prices. Electricity demand is responsive not only to own price but also to climatic conditions, population and economic growth, and prices of other fuels. To the extent that these drivers of electricity demand are predictable—significant uncertainty characterizes many of these variables, especially over

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the long term—an assessment of how they influence consumers' choices regarding electricity consumption facilitates informed policymaking.

Regional and seasonal differences in the mix of fuels and technologies used to produce electricity can drive regional and seasonal differences in the outcomes of any policy that affects electricity production. Demand behavior that varies regionally and seasonally could compound or mitigate such differences. Regional variation in demand behavior is to be expected, given regional differences in infrastructure,[1] the electricity-using capital stock, and consumer preferences that may be heterogeneous. In the nonresidential sectors, variations in the composition of local economic activity also suggest potential regional differences in demand behavior. Seasonal differences in electricity demand are driven by seasonal variation in the demand for energy services—heating, cooling, lighting, water heating, appliance use, and so forth. Since the types of energy services demanded vary seasonally and each energy service varies in electricity consumption intensity, so too will electricity demand show seasonal variation. These regional and seasonal differences may vary with the type of customers. The literature on electricity demand contains little simultaneous consideration of these geographical, temporal, and customer differences. This paper will address this issue by estimating separate, but identically formulated, demand functions for each of nine census divisions with seasonally differentiated coefficients. These demand functions are estimated separately for three customer classes—residential, commercial, and industrial—with identical functional forms but slight variation in the included independent variables.

We adopt a partial adjustment model structure that is an ad hoc formulation capturing the dynamics of the demand stickiness imposed by the capital-intensive nature of electricity consumption. The ideal model would be a structural model derived from a formulation that incorporates individuals and firms that maximize expected utility and profits, respectively, over electricity-using capital investments and electricity consumption to produce electricity services, along with all other goods, within a budget.[2] The data for this model would track purchases, utilization, prices, and characteristics of electricity-consuming equipment at the household and

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[1] These differences exist in the infrastructure for the delivery of energy to end users as well in the stock of buildings.

[2] Dubin and McFadden (1984) use a random utility model to derive such a model, which can be used to jointly estimate energy-using equipment choice behavior and energy consumption. They then implement the model to look at space heating and water heating.

firm level over time. The description of characteristics would include the energy efficiency of the equipment as well as a description of other equipment features that map into the utility and profit functions of consumers and firms. However, these data do not exist, and there is ample evidence that the characterization of preferences necessary to construct a model that approximates the real-world behavior of consumers is unknown (see Train 1985 for the discount rates implied by consumers' energy-related decisions). The partial adjustment formulation is an alternative model of electricity demand that captures the dynamics of demand behavior, allowing for the elasticity of demand with respect to each of its determinants to be expressed in both its short-run and its long-run forms. We give special consideration in this paper to the price elasticities because of the aforementioned policy significance of the price variable.

The models are estimated using a fixed-effects OLS model specification. Because the partial adjustment model includes a lagged dependent variable, autocorrelation can asymptotically bias the coefficient estimates. This problem is addressed by reestimating the model in a two-stage least squares framework. The data are a state-level panel of monthly observations that span the period from 1990 to 2006 and include electricity consumption and prices along with a set of covariates that are assumed to drive consumption.

The paper is organized as follows. We begin with a review of the literature on electricity demand function estimation. Then we present the model that is estimated in this study and the results of the estimation. The conclusion includes some observations regarding the highlights and limitations of this analysis in addition to some suggestions for future research related to electricity demand.

Literature Review

In the absence of detailed household- and firm-level data on electricity consumption and electricity-consuming capital, researchers have turned to a variety of aggregated, ad hoc models of electricity demand.[3] We adopt the partial adjustment formulation that incorporates short-run responses to changes in contemporaneous variables, including price, and longer-run responses through a lagged consumption term. Houthakker and Taylor (1970) developed a dynamic model in which the current level of the state variable is determined by the cumulative effects of past

[3] See Bohi (1981), Bohi and Zimmerman (1984), and Taylor et al. (1984) for an overview of early demand estimation studies and alternative modeling methodologies, and see Dahl (1993) and Dahl and Roman (2004) for a review of energy demand elasticities estimation.

behavior, and the change in the level of the next period's state variable is partly determined by current decisions. Houthakker et al. (1974) and Houthakker (1980) used this approach to model residential electricity demand and estimate price elasticities at the national and regional levels. More recently, Bernstein and Griffin (2005) did a similar analysis estimating national and regional elasticities for the residential and commercial classes. A common finding among these studies is significant differences among the elasticity estimates across the regions. Hsing (1994) estimated elasticities using this approach for six southern states, correcting for cross-sectional heteroskedasticity and autocorrelation. He also finds that regional demand behavior deviates from national average behavior and that the empirical findings are sensitive to model specification. Beierlein et al. (1981) and Lin et al. (1987) used the partial adjustment model with error components and a seemingly unrelated regressions (EC-SUR) procedure to estimate demand equations for electricity and other energy use. Both of these studies simultaneously estimate equations for multiple customer classes and energy sources at a regional, annual level. They find that EC-SUR achieves more efficiency than the OLS and error components approaches.

One difficulty in estimating electricity demand is the potential simultaneity between price and quantity. Because of this problem, some researchers have promoted simultaneous equation approaches over partial adjustment models (Kamerschen and Porter 2004). Baltagi and Griffin (1997) and Baltagi et al. (2002) looked at the forecasting performance of several different estimation techniques with different levels of pooling for the gasoline market and the electricity and natural gas markets, respectively. For the electricity market, Baltagi et al. (2002) found that GLS ranks first among the models tested in predictive performance by having the lowest root mean squared errors (RSME) averaged over a five-year period. GLS was followed by within estimation (OLS with state fixed effects) and within two-stage least squares (2SLS), leading them to conclude that endogeneity problems did not seem to be severe. For the gasoline market, Baltagi and Griffin (1997) also found that standard estimation techniques outperformed simultaneous equation techniques and suggested that the relatively poor performance of the 2SLS estimators in capturing long-run dynamics might be due to the quality of the instruments.

Houthakker (1980), Bernstein and Griffin (2005), and Lin et al. (1987) found pronounced differences among U.S. census divisions in their regional model estimations. Many authors have argued for the importance of modeling at the regional level because unique regional impacts get lost in aggregate models (e.g., Houthakker and Taylor 1970; Houthakker 1980; Taylor et al. 1984). Maddala et al. (1997) explored the issue of pooling and found that heterogeneous time series estimates for each state yield inaccurate signs on the coefficients. They argued that panel data estimates are inaccurate as well because the hypothesis of homogeneity of the coefficients is rejected. They proposed estimating coefficients using shrinkage estimators as a preferred alternative. Baltagi and Griffin (1997) and Baltagi et al. (2002) found that homogeneous estimators were better at forecasting demand than their heterogeneous counterparts and that individual estimation offered the worst out of sample forecasts.

The Partial Adjustment Model

The derivation of the partial adjustment electricity demand model begins with a static representation of a long-run demand function in which $Q^*_{i,t}$ is the level of electricity consumption that would be achieved in U.S. state *i* at time *t* if the capital goods used in the consumption of electricity were perfectly mobile. In the parlance of Houthakker and Taylor (1970), $Q^*_{i,t}$ is the desired level of consumption. Assuming a Cobb Douglas relationship between desired demand and its drivers, Equation (1) defines the long-run demand curve as a function of electricity price, $P_{i,t}$, and a set of covariates, $X_{i,t}$. The long-run price elasticity of demand is denoted as ε_L, β is a vector of coefficients that describes the responsiveness of the long-run level of demand to the nonprice covariates, and α is a constant.

(1) $$Q^*_{i,t} = f(P_{i,t}, X_{i,t}) = \alpha P_{i,t}^{\varepsilon_L} X_{i,t}^{\beta}$$

In reality, capital is not perfectly mobile, and there may exist a habitual component to electricity demand behavior. Thus, Equation (1) by itself is not a sufficient representation of the real-world behavior of electricity consumers. Following Houthakker et al. (1974), we introduce a function to capture the limited capability of consumers to adjust immediately to the long-run equilibrium level of consumption in response to a change in price, income, weather, or other factor. This limited capability is expressed in Equation (2) as parameters θ_1 and θ_{12}, the partial adjustment constraints. The parameter θ_1 captures both the strength of month-to-month behavioral inertia and the monthly rate of capital turnover for types of equipment that are operated in all months (e.g., refrigerators), and the parameter θ_{12} captures the strength of year-to-year behavioral inertia and the rate of capital turnover that has a seasonal usage pattern (e.g., air-conditioners). The parameters θ_1 and θ_{12} will take on values between zero and one, with zero corresponding to a scenario in which consumers are completely unable to adjust consumption toward the long-run equilibrium, and with one corresponding to a scenario in which the entire capital stock can turn over right away and no behavioral habit exists. Both of these scenarios are inconsistent with real-world behavior, and thus values between zero and one are anticipated.

(2) $$\left(\frac{Q_{i,t}{}^2}{Q_{i,t-1}Q_{i,t-12}}\right)=\left(\frac{Q^*_{i,t}}{Q_{i,t-1}}\right)^{\theta_1}\left(\frac{Q^*_{i,t}}{Q_{i,t-12}}\right)^{\theta_{12}}$$

Substituting Equation (1) into a log-log transformation of Equation (2) for $Q^*_{i,t}$ yields Equation (3), which can be econometrically estimated. This estimation, described in the following section, will yield the short-run price elasticity of electricity demand as the coefficient on the term $P_{i,t}$ and the long-run price elasticity will then be calculable as shown in Equation (4), using the values for θ_1 and θ_{12} that will also result from the econometric estimation.

(3) $$\ln Q_{i,t}=\frac{(1-\theta_1)}{2}\ln Q_{i,t-1}+\frac{(1-\theta_{12})}{2}\ln Q_{i,t-12}+\frac{(\theta_1+\theta_{12})}{2}\left(\varepsilon_L\ln P_{i,t}+\beta\ln X_{i,t}\right)$$

(4) $$\varepsilon_L=\frac{2\varepsilon_S}{(\theta_1+\theta_{12})}$$

Data and Estimation

In this paper we estimate Equation (3) separately for each of three customer classes and nine U.S. census divisions. The three customer classes are residential, commercial, and industrial. The data are a state-level panel of monthly observations spanning January 1990 through December 2006. To estimate seasonal variations, we interact many of the independent variables with indicators for each of three seasons: summer, winter, and spring-fall. The seasons correspond with the intra-annual pattern of electricity demand and the summertime ozone season. Summer covers the months from May through September, winter the months from December to February, and spring-fall includes all other months—March, April, October, and November. All monetary values are converted to 2004 dollars using the consumer price index for the residential and commercial classes and the producer price index for the industrial class.

Equation (5) is the general form of the model to be estimated for each region and customer class. The subscript *i* indexes each of the lower 48 states and the District of Columbia, *t* denotes time denominated in months, *c* is customer class, *S* is the set of three seasons, *m*(*t*) and *y*(*t*) are functions mapping time period *t* into the month and year in which *t* occurs, and *I*(•) is the indicator function. The contents of the *Q* and *inc* variables differ across customer classes. For the residential class, *Q* is electricity consumption per capita, for the commercial class it is consumption per customer, and for the industrial class it is total consumption. The *inc* variable is annual disposable income per capita for the residential class and is gross annual state product for the commercial and industrial classes.[4] *P* is the average retail electricity price; it varies by customer class. *HDD* and *CDD* stand for heating and cooling degree days, respectively. *DL* is the number of minutes of daylight in the capital of each state on the 15 day of each month, which varies across months but not across years. The *NGP* variable is the retail price for delivered natural gas and is included only for the residential class. *FE* are state-level fixed effects. The *HDD*, *CDD*, and *inc* variables are not interacted with seasonal dummy variables and therefore do not possess seasonally differentiated coefficients.

$$\ln\left(Q_{i,t}\right)=\sum_{s\in S}\left[\begin{array}{l}\beta_s^{Q1} I\left(m\left(t\right)\in s\right)\ln\left(Q_{i,t-1}\right)+\beta_s^{Q12} I\left(m\left(t\right)\in s\right)\ln\left(Q_{i,t-12}\right)+\\ \beta_s^{P} I\left(m\left(t\right)\in s\right)\ln\left(P_{i,t}\right)+\\ \beta_s^{NGP} I\left(m\left(t\right)\in s\right)\ln\left(NGP_{i,t-12}\right)+\beta_s^{DL} I\left(m\left(t\right)\in s\right)\ln\left(DL_i\right)\end{array}\right]+$$

$$\beta^{HDD} HDD_{i,t}+\beta^{CDD} CDD_{i,t}+\beta^{HDD12} HDD_{i,t-12}+\beta^{CDD12} CDD_{i,t-12}+ \tag{5}$$

$$\beta^{inc}\ln\left(inc_{i,y(t)}\right)+FE_i+\varepsilon_{i,t}$$

The electricity consumption and price data are from the EIA Database Monthly Electric Utility Sales and Revenue Data,[5] the natural gas price data are from the EIA Natural Gas Monthly and SEDS Consumption, Price, and Expenditure Estimates,[6] the heating and cooling degree day data are from the NOAA National Climatic Data Center, income and GSP data are from the Bureau of Economic Analysis, and the daylight data come from the Astronomical Applications Department of the U.S. Naval Observatory.

[4] The data for annual disposable income and gross annual state product have annual, not monthly, frequency.

[5] The definition of the industrial and commercial sectors changed for Tennessee in 1997, as reflected in a large upward adjustment in commercial demand and a complementary downward adjustment in industrial demand between 1996 and 1997. We calculated the shares for both commercial and industrial demand for each month in 1997 as a proportion of total demand for the two sectors. We then treated these as fixed proportions and applied them to all previous years. There are similar discontinuities in the commercial and industrial electricity consumption data for Maryland in 1995 and then again in 2002. As with Tennessee, we applied the fixed proportions for industrial and commercial demand by month in 2002 to corresponding months in all previous years.

[6] Annual data on natural gas price were available for all sectors for all years, but monthly price data were not available for the industrial sector prior to 2001. We calculated the share of annual demand in the industrial sector for each month in 2001. We then used these fixed proportions to estimate monthly-level demand for the previous years. Natural gas prices have clear patterns over the year, and it is more accurate to assume the same distribution of prices among months each year than to assume the same price for every month in a year.

As mentioned above, Q is expressed as electricity consumption per capita and per customer for the residential and commercial classes, but in aggregate for the industrial class. The industrial class is treated in this way for two reasons. First, electricity consumption per industrial customer varies widely because of heterogeneity in the production processes at industrial facilities. Second, industrial customers are, in the long-run, highly mobile compared with the other classes. Hence, the potential for entry and exit of industrial firms would confound the dependent variable, Q, if it were expressed on a per customer basis, since high prices would tend to drive down the numerator (aggregate consumption) while simultaneously driving down the denominator (number of customers).

Both the contemporaneous and the 12-month lags of the heating and cooling degree day variables are included in the model to explicitly capture the short-run utilization choices and the long-run capital choices made in response to temperature. This is necessary because we expect to derive coefficients with the same sign, positive, for both the contemporaneous temperature variables and the partial adjustment coefficients, θ_1 and θ_{12}. If these sign expectations are realized, and they will be, then the model would, in the absence of lagged temperature variables, be incapable of capturing any long-run capital response to temperature if they are negatively correlated. Including the lagged variables allows for short-run utilization choices to be manifest in the contemporaneous variables and long-run capital choices expressed in the lagged variables.

Two primary concerns with estimating Equation (5) are simultaneity between price and quantity and autocorrelation in the presence of lagged dependent variables, which can bias estimation. If electricity prices are determined partly as a function of quantity demanded, then coefficient estimates derived under OLS will be biased. The time period that we analyze, 1990–2006, was characterized by the transition from rate-of-return regulated electricity pricing to electricity market restructuring in many states and the continuation of rate-of-return regulation in others. For those states with ongoing rate-of-return regulation, the price of electricity is based on expectations of total costs and demand that are informed by data from past test years and is thus contemporaneously exogenous. Those states that made the transition to deregulated power markets simultaneously instituted exogenous rate caps. Therefore, electricity prices were largely determined by regulation in the time period we examine, which suggests that they were not a function of quantity demanded. In addition, regulated pricing and rate caps make the development of good instruments for price difficult. We therefore assume that prices are exogenous in this analysis.

As mentioned above, an autocorrelated error term in the presence of lagged dependent variables can lead to biased coefficient estimates. One way to deal with this problem is to use a

2SLS procedure to instrument for the lagged dependent variables by using estimated values, instead of observed values, for the lagged dependent variables. We explore the use of this procedure for estimating Equation (5) in the following section.

Results

The demand model that we estimate includes 27 equations, one for each of three customer classes and nine census divisions. As described in the prior section, because our estimated equations contain lagged dependent variables, we are concerned that autocorrelation may bias coefficient estimates obtained by OLS. We test for autocorrelation using the Ljung-Box test, which applies to each state within a region separately. Table 1 presents the percentage of states that fail to reject the null hypothesis of no autocorrelation in both the 12-month and the 1-month lag for each customer class. The results indicate that there is autocorrelation for a substantial fraction of the states within each region, particularly for the 12-period lag.

Table 1. Percentage of States Exhibiting Autocorrelation in OLS by Ljung-Box Test

	Residential		Commercial		Industrial	
	1 month	12 months	1 month	12 months	1 month	12 months
New England	33%	67%	83%	100%	67%	67%
Middle Atlantic	33%	33%	67%	100%	67%	100%
East North Central	40%	80%	60%	100%	80%	100%
West North Central	43%	71%	43%	86%	71%	100%
South Atlantic	33%	67%	56%	100%	56%	100%
East South Central	25%	75%	50%	100%	75%	100%
West South Central	25%	25%	50%	100%	50%	100%
Mountain	38%	100%	63%	100%	50%	100%
Pacific	67%	67%	33%	100%	67%	100%
National Average	37%	62%	55%	99%	65%	99%

To help remedy the problem of bias, we implement a 2SLS estimation approach in two ways. The first method is to instrument for the presence of the 1-month and 12-month lagged dependent variables using the exogenous variables and electricity prices lagged both 1 and 12 periods. The demand function coefficients resulting from this approach are generally unintuitive and questionable with many coefficients exhibiting theoretically implausible signs. The second method, appealing to the fact that 1 period lag autocorrelation tests show only moderate autocorrelation, instruments for only the 12-month lagged dependent variable using the exogenous variables, the dependant variable lagged 1 period, and electricity prices lagged 12 periods. The results of this 2SLS estimation are also questionable and yield many inappropriate signs. The poor performance of the 2SLS estimator may be explained by the quality of the instruments in the first stage (Baltagi and Griffin 1997). The predetermined lagged dependent variables, which have a lot of explanatory power in our OLS estimations, are left out of the first stage. Thus, the predicted values for lagged demand are a poor approximation of the true values, leading to unreliable second-stage estimation. Given that it is difficult to instrument well for lagged demand and that we have a relatively large sample size, we adopt OLS as a more accurate estimation procedure, and this section describes the results.

To make the discussion of the results more tractable, we aggregate the coefficients along two dimensions: region and time.[7] In Table 2 we present annual weighted average coefficients by region for each of the three customer classes, and in Tables 3a, 3b, and 3c, we present national weighted average coefficients by season. In each case the coefficient estimates are weighted by total demand for the relevant customer class, region, and time period, and implied aggregate standard errors are also presented.

Seasonal Regression Results

The results presented in Table 2 are generally in line with our expectations in terms of signs on the estimated coefficients. With respect to the partial adjustment parameters, the results show that demand for each customer class and in each season is positively related to 1-month lagged demand and to 12-month lagged demand. The coefficients on the contemporaneous price variable have the expected negative sign and are statistically significant.[8] Price effects are discussed in more detail in the section on elasticities, below.

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[7] The coefficient estimates for the 27 individual regressions are available from the authors upon request.

[8] In the underlying detailed regressions, there are a few exceptions to the expected sign result for the coefficient on the price variable, all in the Middle Atlantic region. The coefficient on electricity price is positive and insignificant in the spring-fall for residential customers and in both the summer and the winter for commercial customers.

For the residential and commercial customer classes, the coefficients on the contemporaneous weather variables, which are assumed not to vary by season, are typically highly significant and also have the expected positive signs. The residential and commercial regressions also include 12-month lagged terms on heating and cooling degree days. These lagged variables have the expected negative signs, consistent with a capital turnover story or with behavior to modify electricity demand, like installing more insulation.

Contemporaneous and 12-month lagged heating and cooling degree day variables are also included in the industrial equation. In the case of industrial customers, heating and cooling are less important components of electricity demand (although the extent to which this is true varies by industry) than they are for other types of customers. However, there may be other factors, such as monthly patterns of demand for final products or access to alternative fuels for particular processes, that might be correlated with temperature, and this effect could be picked up by the heating and cooling degree day variables. With the exception of contemporaneous cooling degree days, we find that these weather variables are insignificant on average for the industrial class.

In addition to heating and cooling, we also include a daylight variable in the demand equations. The amount of daylight alters demand for lighting and also heating and cooling because of solar heat gain effects in buildings. We find that when averaged across the entire nation, the minutes of daylight variable has a negative but insignificant effect on residential demand in all three seasons. These aggregate coefficients mask some significant and differentiated effects across regions that are explored below. If we break down the spring-fall results by region, we find that the effect of more minutes of daylight on residential electricity demand is mixed, with positive and significant effects in some of the southern regions, where heat gain is likely more of an issue, and negative effects in other regions, where reduced demand for lighting may trump other effects. In the commercial demand equation, the daylight variable has a positive and significant effect on electricity demand in the summer but is insignificant otherwise, as it is for the industrial sector in all seasons.

We also include 12-month lagged natural gas prices in all the demand equations to capture the potential effect of past increases in the price of a substitute fuel on electricity demand currently. The logic for using the prior year’s price is to allow time for substitution away from natural gas–using equipment to electricity-using equipment or vice versa. Aggregating to the national level, we find that residential electricity demand responds positively to changes in lagged natural gas price in all seasons, but the positive response is not statistically significant.

For the commercial and industrial sectors, the coefficient on this price variable is negative in some seasons and positive in others, but also not statistically significant.

Table 2. National Weighted Average Coefficient Estimates by Customer Class and Season

(weighted standard errors in parentheses)

		Q_{t-1}	Q_{t-12}	P_t	$INC_t/GASP_t$	HDD_t	CDD_t	HDD_{t-12}	CDD_{t-12}	DL_t	NGP_{t-12}
Residential	Summer	0.22***	0.38***	-0.15***						-0.04	0.03
		(0.03)	(0.04)	(0.04)						(0.04)	(0.02)
	Winter	0.11***	0.59***	-0.11**						-0.03	0.01
		(0.03)	(0.04)	(0.04)						(0.04)	(0.02)
	Spring/Fall	0.20***	0.49***	-0.12***						-0.03	0.00
		(0.03)	(0.05)	(0.04)						(0.04)	(0.02)
	Annual Average	0.18***	0.47***	-0.13***	0.11***	4.0E-4***	1.2E-3***	-2.0E-4***	-3.6E-4***	-0.03	0.02
		(0.03)	(0.04)	(0.04)	(0.03)	(2.4E-5)	(4.8E-5)	(2.8E-5)	(7.2E-5)	(0.04)	(0.02)
Commercial	Summer	0.34***	0.37***	-0.12***						0.07*	0.00
		(0.04)	(0.05)	(0.03)						(0.04)	(0.01)
	Winter	0.23***	0.52***	-0.08**						0.04	-0.01
		(0.07)	(0.06)	(0.04)						(0.04)	(0.02)
	Spring/Fall	0.41***	0.34***	-0.10***						0.04	0.01
		(0.07)	(0.07)	(0.03)						(0.04)	(0.01)
	Annual Average	0.34***	0.40***	-0.11***	0.06**	1.2E-4***	5.3E-4***	-4.3E-5**	-2.1E-4***	0.05	0.00
		(0.06)	(0.06)	(0.03)	(0.03)	(2.0E-5)	(4.4E-5)	(2.0E-5)	(5.0E-5)	(0.04)	(0.01)
Industrial	Summer	0.50***	0.28***	-0.14***						0.04	0.00
		(0.06)	(0.06)	(0.03)						(0.04)	(0.01)
	Winter	0.47***	0.32***	-0.19***						0.04	-0.01
		(0.08)	(0.08)	(0.05)						(0.05)	(0.01)
	Spring/Fall	0.51***	0.28***	-0.15***						0.02	0.00
		(0.07)	(0.06)	(0.03)						(0.04)	(0.01)
	Annual Average	0.50***	0.29***	-0.16***	0.01	2.2E-5	1.5E-4***	1.1E-5	-3.5E-5	0.04	0.00
		(0.07)	(0.07)	(0.04)	(0.02)	(2.5E-5)	(5.2E-5)	(2.7E-5)	(4.9E-5)	(0.04)	(0.01)

Lastly, the demand regressions for all of the customer classes include a relevant income variable. For the residential equations, the income variable is per capita disposable income, and aggregating across regions, it has a positive coefficient.[9] The commercial regressions relate per customer electricity demand to gross state product. This relationship turns out to be positive and statistically significant. Gross state product is also used as the income variable in the industrial equations, where the national average result suggests much less significance but covers up important differences across regions, which are discussed below.

Regional Annual Results

The three panels of Table 3 illustrate how the results for each customer class vary across regions. For all three customer classes, the coefficients on the two lagged output variables are positive and highly significant in all cases. The coefficient on the electricity price variable also has the expected negative sign for all customer classes in all regions, although in the Middle Atlantic the price effect is not significantly different from zero for the residential and commercial classes.

At the regional level, the contemporaneous weather variables typically have a positive and significant effect on regional electricity demand for both the residential and the commercial customer classes. The 12-month lagged weather variables have the expected negative sign in all the residential regressions, although the sign on the lagged heating degree days variable deviates from expectations in the commercial regression for the Middle Atlantic. For the industrial sector, the contemporaneous cooling degree days variable has a positive and significant effect on electricity demand in almost all regions, while the coefficient on heating degree days is typically positive but insignificant. The coefficients on the lagged heating and cooling degree day variables are more mixed across the regions.

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[9] In the Pacific region there is a statistically insignificant negative relationship between income and per capita residental electricity demand.

Table 3a. Regional Annual Weighted Average Coefficients for the Residential Customer Class

(weighted standard errors in parentheses)

Residential	Q_{t-1}	Q_{t-12}	P_t	$INC_t/GASP_t$	HDD_t	CDD_t	HDD_{t-12}	CDD_{t-12}	DL_t	NGP_{t-12}
New England	0.14***	0.52***	-0.17***	0.06**	2.6E-4***	1.1E-3***	-1.4E-4***	-4.3E-4***	-0.12***	0.02
	(0.04)	(0.05)	(0.03)	(0.02)	(1.6E-5)	(5.4E-5)	(1.8E-5)	(7.1E-5)	(0.04)	(0.02)
Middle Atlantic	0.21***	0.50***	-0.05	0.15***	2.9E-4***	1.3E-3***	-1.1E-4***	-3.8E-4***	-0.10***	0.02
	(0.03)	(0.05)	(0.05)	(0.04)	(1.9E-5)	(5.5E-5)	(2.3E-5)	(8.6E-5)	(0.03)	(0.02)
East North Central	0.12***	0.58***	-0.12***	0.10***	2.7E-4***	1.6E-3***	-1.7E-4***	-5.6E-4***	-0.07**	-0.01
	(0.03)	(0.05)	(0.03)	(0.03)	(1.5E-5)	(4.3E-5)	(2.4E-5)	(8.2E-5)	(0.03)	(0.02)
West North Central	0.12***	0.57***	-0.21***	0.03	2.6E-4***	1.5E-3***	-1.9E-4***	-6.1E-4***	-0.12***	0.00
	(0.02)	(0.03)	(0.04)	(0.03)	(1.2E-5)	(4.1E-5)	(1.3E-5)	(6.6E-5)	(0.02)	(0.01)
South Atlantic	0.17***	0.40***	-0.08**	0.21***	5.1E-4***	1.2E-3***	-2.8E-4***	-2.5E-4***	-0.08**	0.01
	(0.02)	(0.04)	(0.04)	(0.04)	(2.1E-5)	(3.8E-5)	(2.4E-5)	(6.4E-5)	(0.04)	(0.02)
East South Central	0.21***	0.34***	-0.32***	0.07	5.5E-4***	1.1E-3***	-1.6E-4***	-2.1E-4***	0.07	0.07**
	(0.03)	(0.05)	(0.06)	(0.05)	(3.5E-5)	(5.4E-5)	(4.1E-5)	(7.9E-5)	(0.06)	(0.03)
West South Central	0.25***	0.43***	-0.11***	0.13***	4.6E-4***	8.6E-4***	-2.5E-4***	-2.7E-4***	0.19***	0.01
	(0.03)	(0.04)	(0.04)	(0.03)	(3.4E-5)	(4.6E-5)	(3.5E-5)	(6.1E-5)	(0.06)	(0.03)
Mountain	0.10***	0.66***	-0.19***	0.02	2.7E-4***	9.1E-4***	-1.8E-4***	-4.8E-4***	-0.08***	0.03**
	(0.02)	(0.04)	(0.04)	(0.02)	(1.6E-5)	(4.7E-5)	(1.6E-5)	(5.4E-5)	(0.03)	(0.01)
Pacific	0.28***	0.43***	-0.13***	-0.02	4.6E-4***	1.2E-3***	-1.5E-4***	-2.8E-4***	-0.08***	0.02
	(0.04)	(0.05)	(0.04)	(0.02)	(3.1E-5)	(8.5E-5)	(3.2E-5)	(9.9E-5)	(0.03)	(0.02)
National Average	0.18***	0.47***	-0.13***	0.11***	4.0E-4***	1.2E-3***	-2.0E-4***	-3.6E-4***	-0.03	0.02
	(0.03)	(0.04)	(0.04)	(0.03)	(2.4E-5)	(4.8E-5)	(2.8E-5)	(7.2E-5)	(0.04)	(0.02)

Table 3b. Regional Annual Weighted Average Coefficients for the Commercial Customer Class

(weighted standard errors in parentheses)

Commercial	Q_{t-1}	Q_{t-12}	P_t	$INC_t/GASP_t$	HDD_t	CDD_t	HDD_{t-12}	CDD_{t-12}	DL_t	NGP_{t-12}
New England	0.46***	0.23***	-0.13***	0.08***	1.1E-4***	6.6E-4***	-2.6E-5	-9.6E-5	-0.07**	0.00
	(0.08)	(0.07)	(0.04)	(0.03)	(2.0E-5)	(5.4E-5)	(1.9E-5)	(7.3E-5)	(0.03)	(0.02)
Middle Atlantic	0.46***	0.24***	-0.01	0.19***	1.1E-4***	5.2E-4***	3.6E-5*	-7.8E-5	0.02	-0.01
	(0.05)	(0.06)	(0.03)	(0.05)	(1.8E-5)	(4.6E-5)	(1.8E-5)	(5.7E-5)	(0.03)	(0.01)
East North Central	0.22***	0.26***	-0.17***	0.16***	9.4E-5***	6.9E-4***	-5.8E-5***	-1.5E-4***	-0.03	-0.04**
	(0.08)	(0.08)	(0.05)	(0.05)	(1.8E-5)	(3.8E-5)	(2.0E-5)	(5.1E-5)	(0.04)	(0.02)
West North Central	0.44***	0.42***	-0.14***	0.03	1.0E-4***	6.7E-4***	-4.1E-5***	-3.5E-4***	0.01	-0.01
	(0.05)	(0.05)	(0.04)	(0.04)	(1.3E-5)	(4.4E-5)	(1.5E-5)	(5.6E-5)	(0.03)	(0.01)
South Atlantic	0.22***	0.61***	-0.04*	0.03**	1.7E-4***	5.0E-4***	-1.0E-4***	-3.9E-4***	0.11***	0.00
	(0.04)	(0.05)	(0.02)	(0.01)	(1.6E-5)	(2.5E-5)	(1.9E-5)	(3.0E-5)	(0.03)	(0.01)
East South Central	0.33***	0.48***	-0.22***	-0.05	1.5E-4***	4.5E-4***	-4.3E-5*	-3.2E-4***	0.19***	0.00
	(0.04)	(0.05)	(0.04)	(0.03)	(2.1E-5)	(3.6E-5)	(2.4E-5)	(4.0E-5)	(0.04)	(0.02)
West South Central	0.45***	0.31***	-0.08***	0.02	1.2E-4***	3.5E-4***	-2.1E-5	-1.4E-4***	0.17**	0.00
	(0.07)	(0.07)	(0.03)	(0.02)	(2.7E-5)	(3.6E-5)	(2.6E-5)	(3.8E-5)	(0.08)	(0.02)
Mountain	0.30***	0.51***	-0.14***	-0.02	8.8E-5***	4.4E-4***	-2.6E-5	-2.8E-4***	0.07**	0.02
	(0.05)	(0.05)	(0.04)	(0.02)	(1.7E-5)	(3.7E-5)	(1.7E-5)	(4.1E-5)	(0.03)	(0.01)
Pacific	0.36***	0.39***	-0.17***	0.03*	7.1E-5***	5.0E-4***	-4.0E-5	-4.9E-5	-0.03	0.03
	(0.05)	(0.06)	(0.04)	(0.02)	(2.7E-5)	(8.5E-5)	(2.5E-5)	(8.4E-5)	(0.02)	(0.02)
National Average	0.34***	0.40***	-0.11***	0.06**	1.2E-4***	5.3E-4***	-4.3E-5**	-2.1E-4***	0.05	0.00
	(0.06)	(0.06)	(0.03)	(0.03)	(2.0E-5)	(4.4E-5)	(2.0E-5)	(5.0E-5)	(0.04)	(0.01)

Table 3c. Regional Annual Weighted Average Coefficients for the Industrial Customer Class

(weighted standard errors in parentheses)

Industrial	Q_{t-1}	Q_{t-12}	P_t	$INC_t/GASP_t$	HDD_t	CDD_t	HDD_{t-12}	CDD_{t-12}	DL_t	NGP_{t-12}
New England	0.52***	0.27***	-0.08**	-0.06***	2.5E-5	2.5E-4***	-1.4E-5	-1.7E-4**	0.04	-0.01
	(0.06)	(0.06)	(0.03)	(0.02)	(2.1E-5)	(7.0E-5)	(2.0E-5)	(6.8E-5)	(0.03)	(0.01)
Middle Atlantic	0.51***	0.34***	-0.20***	-0.19***	4.5E-5**	2.9E-4***	9.9E-6	-1.4E-4**	0.07	0.01
	(0.08)	(0.08)	(0.04)	(0.03)	(2.1E-5)	(7.8E-5)	(2.2E-5)	(7.0E-5)	(0.05)	(0.01)
East North Central	0.55***	0.28***	-0.09***	0.01	2.5E-5	1.2E-4***	-9.3E-6	-8.8E-5**	0.10***	0.00
	(0.07)	(0.07)	(0.03)	(0.02)	(1.6E-5)	(4.3E-5)	(1.7E-5)	(4.1E-5)	(0.03)	(0.01)
West North Central	0.64***	0.27***	-0.11***	0.00	1.2E-5	1.8E-4***	2.5E-5*	-7.2E-5**	0.10***	0.00
	(0.05)	(0.05)	(0.04)	(0.02)	(1.3E-5)	(4.0E-5)	(1.3E-5)	(3.5E-5)	(0.02)	(0.01)
South Atlantic	0.32***	0.42***	-0.16***	0.02	2.3E-5	2.3E-4***	-2.9E-5	-1.1E-4**	-0.03	-0.01
	(0.07)	(0.08)	(0.04)	(0.02)	(3.0E-5)	(5.0E-5)	(3.5E-5)	(4.4E-5)	(0.05)	(0.01)
East South Central	0.43***	0.21***	-0.19***	0.03	1.4E-5	-2.0E-5	2.8E-5	5.9E-5	-0.06	0.02
	(0.07)	(0.07)	(0.05)	(0.04)	(2.3E-5)	(4.2E-5)	(2.4E-5)	(3.8E-5)	(0.04)	(0.01)
West South Central	0.43***	0.35***	-0.11***	0.08***	1.0E-6	6.1E-5*	-9.1E-6	-3.6E-5	0.01	0.00
	(0.06)	(0.05)	(0.03)	(0.02)	(2.8E-5)	(3.1E-5)	(3.2E-5)	(3.7E-5)	(0.05)	(0.01)
Mountain	0.59***	0.25***	-0.18***	0.04***	2.7E-5	1.7E-4***	1.6E-5	-5.5E-5	0.10**	0.01
	(0.06)	(0.05)	(0.05)	(0.01)	(2.4E-5)	(4.9E-5)	(2.6E-5)	(4.6E-5)	(0.05)	(0.01)
Pacific	0.67***	0.10**	-0.31***	0.02	4.0E-5	2.2E-4**	1.3E-4***	2.6E-4**	0.04	-0.02
	(0.05)	(0.05)	(0.04)	(0.02)	(4.2E-5)	(1.0E-4)	(4.1E-5)	(1.0E-4)	(0.04)	(0.02)
National Average	0.50***	0.29***	-0.16***	0.01	2.2E-5	1.5E-4***	1.1E-5	-3.5E-5	0.04	0.00
	(0.07)	(0.07)	(0.04)	(0.02)	(2.5E-5)	(5.2E-5)	(2.7E-5)	(4.9E-5)	(0.04)	(0.01)

When aggregated over the course of a year, the daylight variable has a negative effect on residential electricity demand for many regions. However, the effect of daylight is positive in the East South-Central and West South-Central regions, significantly so in the case of the latter. In these southern regions, the effect of increased demand for cooling is stronger than the effect of decreased demand for lighting as days get longer. In the other seven regions, the lower demand for lighting appears to be the stronger driver. For the commercial sector, the effect of daylight hours on regional demand is more mixed and typically not significant, although the annual numbers mask important seasonal effects within certain regions, some of which are negative and some of which are positive and thus are netted out in the annual aggregation. Daylight hours are also included in the industrial equations but are significant only where the annual average coefficient tends to be positive.

The findings regarding the effects of the relevant income variable vary significantly across the customer classes. For the residential class, income typically has a positive effect on annual demand, although it is insignificant in some regions. One exception is in the Pacific region, where increases in income have a negative but insignificant effect on demand. This result could be partially due to the fact that California, a high-income Pacific state, has strong energy efficiency programs and strict appliance and building standards that help temper growth in electricity demand. The coefficient values for gross state product, the measure of income used in the commercial sector regressions, is positive for five of the nine regions and not significantly different from zero in the others. For the income variable in the industrial demand equations, there is regional variability. In New England and the Middle Atlantic, the effect is significantly negative. In the rest of the country, the coefficient on gross state product is positive, significantly so in the West South-Central and Mountain regions.

Price Elasticities

The partial adjustment model that we use allows us to estimate both short-run and long-run price elasticities of demand for each customer class, region, and season. The short-run price elasticity is simply the coefficient on contemporaneous electricity price in the partial adjustment demand equation. The long-run elasticity is calculated using the short-run elasticity and the coefficients on the two lagged demand terms. Using Equation (4) combined with the notation of Equation (5), we define the short-run and long-run elasticities, respectively, for each customer class and census division, and for each season s, as follows:

(6) $$\varepsilon_s^{sr} = \beta_s^P$$

(7) $$\varepsilon_s^{lr} = \frac{\varepsilon_s^{sr}}{\left(1 - \beta_s^{Q1} - \beta_s^{Q12}\right)}$$

The 27 estimated demand equations yield 81 short- and long-run elasticity estimates. In Table 4, we present aggregate results in annual averages for each region and for the nation as a whole in the top panel, and in national averages for each season and for the year as a whole in the bottom panel. The results reported in the last row of Table 4 indicate that the national, annual average short-run price elasticities of demand are most elastic in the industrial class and least so in the commercial class. In the long run, the residential and industrial classes exhibit similar price responsiveness, with the commercial class being 25 percent less elastic. The aggregate short-run demand elasticity across all customer classes is –0.13, and the long-run elasticity is almost three times as great, at –0.36. In both the short and long run, demand for electricity is clearly price inelastic.

Table 4. Short-Run and Long-Run Price Elasticity of Electricity Demand

	Residential		Commercial		Industrial	
	Short-run	Long-run	Short-run	Long-run	Short-run	Long-run
Annual Average						
New England	-0.17	-0.51	-0.13	-0.37	-0.08	-0.20
Middle Atlantic	-0.05	-0.14	-0.01	-0.02	-0.20	-0.48
East North Central	-0.12	-0.36	-0.17	-0.70	-0.09	-0.22
West North Central	-0.21	-0.61	-0.14	-0.34	-0.11	-0.25
South Atlantic	-0.08	-0.27	-0.04	-0.09	-0.16	-0.44
East South Central	-0.32	-1.16	-0.22	-0.54	-0.19	-0.61
West South Central	-0.11	-0.33	-0.08	-0.22	-0.11	-0.28
Mountain	-0.19	-0.49	-0.14	-0.34	-0.18	-0.42
Pacific	-0.13	-0.37	-0.17	-0.45	-0.31	-0.82
National Average	-0.13	-0.40	-0.11	-0.29	-0.16	-0.40
National Average						
Summer	-0.15	-0.52	-0.12	-0.34	-0.14	-0.36
Winter	-0.11	-0.32	-0.08	-0.22	-0.19	-0.48
Spring/Fall	-0.12	-0.35	-0.10	-0.27	-0.15	-0.39
Annual Average	-0.13	-0.40	-0.11	-0.29	-0.16	-0.40

Overall, the national average elasticity results reported in the last row of Table 4 appear to fall at the low end of or just outside the range of results reported in the literature. Table 5 shows results reported in several econometric studies that look at national electricity demand by customer class. Bohi and Zimmerman (1984) and Dahl and Roman (2004) are survey studies; the rest report original results. Our national average short- and long-run elasticity results for the residential class tend to be more inelastic than the finding in the literature, especially in the short run. For the commercial sector, our results are at the low end of the range, and our long-run elasticity for the industrial class is below the range of earlier studies. Our demand-weighted average elasticities across all customer classes, –0.13 in the short run and –0.36 in the long run, line up well with Dahl and Roman.

Table 5. National Electricty Own-Price Elasticity Estimates from the Literature

Customer Class	*Reference*	*Short-Run*	*Long-Run*
Residential	Bohi and Zimmerman (1984) (consensus)	–0.2	–0.7
	Dahl and Roman (2004)	–0.23	–0.43
	Supawat (2000)	–0.21	–0.98
	Espey and Espey (2004)	–0.35	–0.85
	Bernstein and Griffin (2005)	–0.24	–0.32
Commercial	Bohi and Zimmerman (1984)	0	–0.26
	Bernstein and Griffin (2005)	–0.21	–0.97
Industrial	Bohi and Zimmerman (1984) (dynamic)	–0.11	–3.26
	Dahl and Roman (2004)	–0.14	–0.56
	Taylor (1977)	–0.22	–1.63
All	Dahl and Roman (2004)	–0.14	–0.32

In addition to varying across customer class, elasticities also vary substantially across regions within a given customer class. Comparing the interquartile range with the median value suggests that the long-run and short-run commercial elasticities exhibit the most variation across regions. The bottom half of Table 4 displays the national average short- and long-run demand elasticities by customer class and season. This table shows that there tends to be some variability in price responsiveness across seasons, for all three customer classes. For the industrial class, both short- and long-run price responsiveness tends to be highest in the winter. However, for the other two customer classes, long-run price responsiveness tends to be highest in the summer and lowest in the winter. In the summer, cooling is one of the primary end-uses for electricity in the residential and commercial classes. Therefore, behavioral responses, such as adjustments in temperature settings, could have a significant effect on electricity bills. In the winter, electricity is not the primary energy source for heating, so there is less flexibility to modify behavior to reduce consumption.

Conclusion

The growing impetus for federal policies to restrict emissions of greenhouse gases in the United States and for complementary policies to reduce energy demand and encourage greater use of non-CO_2-emitting energy sources is leading to an explosion of policy proposals to accomplish these goals. Such policies will have implications for how electricity is produced and for the cost of electricity to consumers. To understand how these policies are likely to affect electricity demand and the electricity sector more generally, it's important to have a quantitative representation of electricity demand behavior. In this paper we use monthly data on electricity consumption and its covariates by customer class to estimate regional models of electricity demand with seasonally differentiated coefficients. We use a partial adjustment approach that provides a reduced-form representation of the effects of long-lived capital on electricity demand and allows us to estimate both the short- and the long-run price elasticities of demand. Within the context of an electricity market equilibrium model, these demand functions can be used to predict the effects on electricity demand of a range of policies that affect electricity prices.

We find that demand for electricity is highly price inelastic in the short run and less so in the long run and that price elasticities vary by customer class, region, and season. Consistent with earlier literature, we find a national, annual average short-run price elasticity across all customer classes of –0.13 and a long-run elasticity of –0.36. Industrial customers exhibit the greatest price responsiveness of demand in the short run, and residential and industrial customers have identical levels of price responsiveness in the long run. Commercial customers are the least price responsive of the three customer classes over both time frames. We also find important seasonal and regional differences in price responsiveness.

One important caveat to our findings is that recent changes in regulations and other factors will likely affect electricity demand in ways that are not captured in the model. These include more stringent energy efficiency standards for appliances and expanded efficiency programs managed by utilities and governments. A superior model of electricity demand would explicitly characterize the policies and programs that affect electricity consumption efficiency, but sufficient data are not currently available. Nonetheless, these effects are manifest in the consumption data that underpin the model and thus the application of these demand functions to forecasting analysis would implicitly assume that the energy efficiency programs of the past will be continued into the future at a constant level. Further research on the effects of energy efficiency programs on electricity demand at the state level will be required to untangle these effects.[10]

Ideally, electricity demand equations would be part of a structural model that includes information about capital stock and explicit decisions about capital turnover and utilization in response to changes in current and expected prices of electricity and other energy sources. Currently, the lack of data required to estimate such a model for the full range of end-uses of electricity means that any such model must necessarily focus on a subset of end-uses and therefore be of limited value for broad policy analysis. The model developed in this paper provides a useful reduced-form representation of electricity demand that can be incorporated into an equilibrium model of the electricity sector to provide important information about short-run and long-run responses to changes in electricity prices resulting from various policy initiatives.

[10] Loughran and Kulick (2004) look at the effects of energy efficiency spending on total electricity demand using utility-level data on energy efficiency expenditures. Horowitz (2004) uses information on reported electricity savings from energy efficiency programs by customer class to classify states as high or low performers with respect to energy efficiency programs and then uses a differences-in-differences analysis to explore the effects of demand side management performance on growth in electricity demand by customer class. One issue with this analysis is that the level of energy savings associated with efficiency programs is difficult to measure and thus potentially subject to substantial measurement error.

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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.

Robert L. McGee, Jr.
Regulatory and Pricing Manager

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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		Program Total	
	@ Meter	@ Generator	@ Meter	@ 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		Program Total	
	@ Meter	@ Generator	@ Meter	@ 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 @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ 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 @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ 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		Program Total	
	@ Meter	@ Generator	@ Meter	@ 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 @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ 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 @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ 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 @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ 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 @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ 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 @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ 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		Program Total	
	@ Meter	@ Generator	@ Meter	@ 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 @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ 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		Program Total	
	@ Meter	@ Generator	@ Meter	@ 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 @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ 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 @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ 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 @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ 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		Program Total	
	@ Meter	@ Generator	@ Meter	@ 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.
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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

		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	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**										
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**										
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**

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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		Program Total	
	@ Meter	@ Generator	@ Meter	@ 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		Program Total	
	@ Meter	@ Generator	@ Meter	@ 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 Summer kW	Meter Winter kW	Meter Energy kWh	Generator Summer kW	Generator Winter kW	Generator Energy kWh
2015	**0**	**0**	**0**	**0**	**0**	**0**
2016						
2017						
2018						
2019						
Cumulative	0	0	0	0	0	0

Projects - 2015	Meter Summer kW	Meter Winter kW	Meter Energy kWh	Generator Summer kW	Generator Winter kW	Generator 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		Program Total	
	@ Meter	@ Generator	@ Meter	@ 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 @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Winter kW Reduction	0.00	0.00	0	0
Summer kW Reduction	0.41	0.50	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 @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ 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.
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
2010-2015 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	

[Service Date March 25, 2015]

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFIC POWER & LIGHT COMPANY, a Division of PacifiCorp, Respondent.	DOCKET UE-140762 *(Consolidated)* ORDER 08 FINAL ORDER REJECTING TARIFF SHEETS; RESOLVING CONTESTED ISSUES; AUTHORIZING AND REQUIRING COMPLIANCE FILINGS;
In the Matter of PACIFIC POWER & LIGHT COMPANY Petition for an Order Approving Deferral of the Washington-Allocated Revenue Requirement Associated with the Merwin Fish Collector.	DOCKET UE-140617 (*Consolidated*) GRANTING, IN PART, RECOVERY OF DEFERRED COSTS;
In the Matter of PACIFIC POWER & LIGHT COMPANY Petition for an Order Approving Deferral of Costs Related to Colstrip Outage.	DOCKET UE-131384 (*Consolidated*) DENYING PETITION FOR ACCOUNTING ORDER;
In the Matter of PACIFIC POWER & LIGHT COMPANY Petition for an Order Approving Deferral of Costs Related to Declining Hydro Generation.	DOCKET UE-140094 (*Consolidated*) DENYING PETITION FOR ACCOUNTING ORDER

Synopsis*: The Commission rejects revised tariff sheets Pacific Power & Light Company (Pacific Power or Company) filed on May 1, 2014, that would have increased rates by 8.5 percent, raising $27.2 million in additional revenue for the Company, if approved by the Commission. The Commission, considering the full record, authorizes and requires Pacific Power to file revised tariff sheets stating rates that will recover $9.6 million in additional revenue, resulting in a 3.0 percent increase in rates that the Commission finds to be reasonable.*

The Commission rejects Pacific Power's request that it revisit the Company's recently rejected proposal to revise the West Control Area inter-jurisdictional cost allocation methodology applicable to the cost of Qualifying Facilities under the Public Utilities Regulatory Policies Act (PURPA)[1]. In addition, the Commission exercises its discretion to not revisit the interrelated questions of what the rate of return on equity component and equity ratio should be in Pacific Power's capital structure. The Commission heard and decided these issues just five months prior to Pacific Power filing this case and shortly after the Company appealed these decisions to Division II of the Washington State Court of Appeals. The Commission will not entertain the Company's proposals to rehear them in this proceeding.

The Commission resolves several contested pro forma expense adjustments, including adjustments related to the Company's net power costs. In connection with power cost recovery going forward, the Commission requires Pacific Power, following further proceedings, to file appropriate tariff sheets to implement a properly designed Power Cost Adjustment Mechanism (PCAM) that will protect the Company from extra-normal power cost variability while giving Pacific Power adequate incentive to manage carefully its full power portfolio.

The Commission approves various additions to rate base, including the known and measurable pro forma costs of certain facilities that are now used and useful, albeit with post-test period in-service dates.

The rates determined in this Order to be fair, just, reasonable, and sufficient are based on a capital structure of 49.10 percent equity, 50.69 percent long-term debt, 0.19 percent short-term debt, and 0.02 percent preferred stock, with a 9.5 percent

[1] Pub.L. 95–617, 92 Stat. 3117 (enacted November 9, 1978).

return on equity, a 5.19 percent cost of long-term debt, a 1.73 percent cost of short-term debt, and a 6.75 cost of preferred stock. This results in an overall rate of return of 7.30 percent.

The Commission rejects Pacific Power's and Staff's respective recommendations for significant increases in the residential customer basic charge and Staff's related recommendation for the addition of a third inverted block rate that would apply to higher levels of consumption by residential customers. The Commission restates its preference for a decoupling mechanism to address issues of fixed cost recovery while promoting conservation investment and encouraging, or at least not impeding, the development of distributed generation.

Finally, the Commission approves increased funding for PacifiCorp's Low Income Bill Assistance Program consistent with the requirements of the five-year low-income bill assistance program approved in Docket UE-111190 in March 2012. We encourage continued efforts by the Company, Staff, the Energy Project, and others who recognize the importance of ensuring that low-income customers have access to the vital services Pacific Power provides, to find innovative means to provide it.

In the consolidated dockets, the Commission grants Pacific Power's proposals to refund deferred over-recoveries of depreciation expense, and to recover deferred Operating & Maintenance expense and depreciation expense (i.e., return of investment) for the Merwin Fish Collector Project (Merwin Project), but denies recovery of deferred interest (i.e., return on the Merwin Project investment). The Company will recover return on the Merwin Project investment in rate base going forward, just as in the case of any other post-test period plant addition.

The Commission denies Pacific Power's petitions for accounting orders allowing deferred treatment of replacement power costs in Docket UE-131384 (Colstrip Outage) and Docket UE-140094 (Hydropower Deferral). Neither request demonstrates extraordinary costs that might support such treatment. We prefer to address volatility in power costs through a properly designed Power Cost Adjustment Mechanism (PCAM), which we require the Company to file in this Order, rather than continued filing of petitions to defer accounting treatment of power costs.

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SUMMARY

1 **PROCEEDING:** Pacific Power & Light Company (Pacific Power), an operating division of PacifiCorp,[2] filed this general rate case (GRC) proceeding with the Washington Utilities and Transportation Commission (Commission) in Docket UE-140762 on May 1, 2014, seeking to recover additional revenue of approximately $27.2 million.[3] The Company also requests deferral accounting treatment and amortization over one year of $4.9 million related to replacement power costs arising from an outage at Unit 4 of the Colstrip generating plant (Docket UE-131384) and anticipated low hydropower conditions during 2014 (Docket UE-140094). On April 14, 2014, PacifiCorp filed with the Commission in Docket UE-140617 an accounting petition seeking authorization to defer approximately $1.7 million per year ($142,000 per month) associated with the Merwin Fish Collector Project (Merwin Project). The Commission granted the accounting petition on May 29, 2014.[4] Pacific Power now requests to recover in rates the deferral balance for the Merwin Project. The Commission consolidated these four dockets.

2 Following public comment hearings in Yakima on September 25, 2014, and in Walla Walla on September 26, 2014, and evidentiary hearings in Olympia on December 16-19, 2014, the parties filed Initial Briefs and Reply Briefs on January 22 and February 3, 2015, respectively. This Final Order resolves all disputed issues in these proceedings.

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[2] PacifiCorp was initially incorporated in 1910 under the laws of the state of Maine under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, it merged with Utah Power and Light Company, a Utah corporation, in a transaction wherein both corporations merged into a newly-formed Oregon corporation that retained the PacifiCorp name. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name of its operating division, Rocky Mountain Power, and to customers in Oregon, Washington and California under the trade name of its operating division, Pacific Power. PacifiCorp's electric generation, commercial and trading, and coal mining functions are operated under the trade name of its third principal operating division PacifiCorp Energy. PacifiCorp is a wholly-owned subsidiary of Berkshire Hathaway Energy which, in turn, is wholly owned by its affiliate, Berkshire Hathaway.

[3] Pacific Power increased its revenue request in its rebuttal testimony filed on November 14, 2014, to $31.9 million, “driven primarily by the Company’s net power cost update” and based on it requested 10 percent return on equity. Dalley, Exh. No. RBD-3T at 1:15-17. By the conclusion of the evidentiary hearing, Pacific Power’s request was at $30,398,178.

[4] *WUTC v. Pacific Power & Light Co*., Docket UE-140617, Order 01 (May 29, 2014).

3 **PARTY REPRESENTATIVES:** Katherine A. McDowell and Adam Lowney, McDowell Rackner & Gibson PC, Portland, Oregon, and Sarah Wallace, Assistant General Counsel, Pacific Power, represent the Company. Patrick J. Oshie, Brett P. Shearer, and Jennifer Cameron-Rulkowski, Assistant Attorneys General, Olympia, represent the Commission's Regulatory Staff (Staff).[5] Simon J. ffitch, Senior Assistant Attorney General, Seattle, represents the Public Counsel Section of the Washington Office of Attorney General (Public Counsel).

4 Melinda J. Davison and Jesse Cowell, Davison Van Cleve, Portland, Oregon, represent the Boise White Paper, L.L.C. (Boise White Paper). Brad M. Purdy, attorney at law, Boise, Idaho, represents the Energy Project.[6] Samuel L. Roberts, Hutchinson, Cox, Coons, Orr & Sherlock PC, Eugene, Oregon, represents Walmart Stores, Inc. (Walmart). Joseph F. Wiedman, Keyes, Fox & Wiedman, Oakland, California, represents The Alliance for Solar Choice.

5 **COMMISSION DETERMINATIONS:** The Commission, on May 14, 2014, suspended and set for hearing the rates Pacific Power originally proposed in its general rate case (GRC) filing, and the petitions for deferral accounting and recovery of replacement power costs associated with the Colstrip outage and hydropower conditions during 2014. On May 29, 2014, the Commission consolidated into the GRC the Merwin deferral matter. Based on the record of this proceeding we find that neither the Company's as-filed rates, nor the revised rate request Pacific Power made through its rebuttal filing and at the conclusion of the advocacy phase, are fair, just and reasonable. We reject Pacific Power's accounting petition and proposed recovery of deferred costs in Docket UE-140094 (low hydropower production), reject the Company's accounting petition and proposed recovery of deferred power costs in

[5] In formal proceedings, such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

[6] The Columbia Rural Electric Association (CREA), represented by Irion Sanger, Davison Van Cleve, Portland, Oregon was granted leave to intervene in this proceeding under the "participation in the public interest" standard in WAC 480-07-355(3) in connection with a single issue that later was withdrawn from the case. In its order granting Pacific Power leave to withdraw the issue, the Commission dismissed CREA as an intervenor as provided in WAC 480-07-355(4).

Docket UE-131384 (Colstrip outage), and reject in part the Company's proposed recovery of deferred costs in Docket UE-140617 (Merwin Project).

6 We find that Pacific Power requires a modest increase in revenue to ensure its prospective rates are sufficient. We specifically find a revenue deficiency of $9,568,464 for Pacific Power's electric service provided in Washington. The updated net power costs determined in this proceeding will establish the initial baseline for a Power Cost Adjustment Mechanism (PCAM) that we require Pacific Power to implement by filing appropriate tariff sheets in compliance with this Order. The Company's new rates, including updated net power costs, will be effective no earlier than April 1, 2015.

7 We decline to adjust the equity ratio and rate of return on equity included in the Company's capital structure. We decided these issues only five months before Pacific Power filed this case and will exercise our discretion not to rehear or decide them in this docket.[7] We also will not rehear the question whether we should change the West Control Area situs allocation methodology for the costs of Qualifying Facilities under PURPA. Not only did we decide these issues within months prior to Pacific Power's filing of this GRC, they also are the subjects of the Company's appeal now pending in Division II of the Washington Court of Appeals. We do not wish to risk disrupting the Court's well-ordered consideration of the matters before it.

8 Washington relies on a hybrid test year approach to ratemaking. Although the Commission starts with a historic test year, we allow *pro forma* adjustments to rate base and expenses that often extend beyond what is known and measurable as of the end of the test year. The Commission, in addition, sets the largest single utility expense, net power costs, on a forward basis using data and cost projections that are as nearly contemporaneous as practicable with the effective date of new rates. The Commission, albeit forward looking in its approach, rejects Pacific Power's efforts to have us determine rates using methods that push too far in the direction of regulatory policies and practices suitable to states that use a future test year approach to ratemaking instead of a hybrid test year approach.

9 Finally, in prior general rate cases the Commission has requested the Company to take advantage of regulatory mechanisms available in Washington that are designed to enhance the ability of utilities to effect timely recovery of their authorized revenue

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[7] *See* RCW 80.04.220.

requirements. Pacific Power has refused to do so. A Power Cost Adjustment Mechanism (PCAM) designed in accordance with the regulatory policy guidance this Commission has given Pacific Power in prior cases is long overdue. We authorize and require Pacific Power to implement a properly designed PCAM in compliance with this Order. The Commission will conduct brief additional proceedings to determine the details required for such a mechanism.

10 In terms of fixed cost recovery, the Commission has expressed and demonstrated its preference for the use of decoupling.[8] The Commission has approved such mechanisms for several companies. Pacific Power has not yet come forward with a fully developed decoupling proposal. In this Order we invite the Company, Staff, and other interested parties to put such a proposal before the Commission in Pacific Power's next general rate case.

<u>MEMORANDUM</u>

I. Background and Procedural History

11 On May 1, 2014, Pacific Power filed revised tariff sheets with the Commission to increase rates and charges for electric service provided to customers in the state of Washington. The Company requested an electric rate increase of $27.2 million, or 8.5 percent. In addition, the Company sought deferral accounting authority and amortization over one year of $4.9 million, or 1.5 percent, related to replacement power to cover an outage at Unit 4 of the Colstrip generating plant (Docket UE-131384) and low hydropower conditions (Docket UE-140094). The Company proposes to recover these deferred costs via a separate tariff rider, Schedule 92.

12 On April 14, 2014, the Company filed with the Commission in Docket UE-140617 a new tariff - Schedule 90 entitled "Hydro Investment Adjustment." The purpose of this schedule was to recover costs associated with the Merwin Fish Collector project (Merwin Project). As an alternative to allowing the separate tariff rider to go into effect by operation of law, Pacific Power included in its filing an accounting petition for authorization to defer the revenue requirement of approximately $1.7 million per year ($142,000 per month) associated with the Merwin Project.

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[8] *See In re WUTC Investigation into Energy Conservation Incentives,* Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, including Decoupling, To Encourage Utilities To Meet or Exceed Their Conservation Targets at (Nov. 4, 2010) (Decoupling Policy Statement).

13 In Order 01 in Docket UE-140762, entered on May 14, 2014, the Commission suspended the tariff sheets Pacific Power filed on May 1, 2014. On May 29, 2014, the Commission entered Order 03 in Docket UE-140762 and Order 01 in Docket UE-140617, consolidating the dockets, suspending the tariff sheets filed on April 14, 2014, and authorizing the Merwin Project deferral. In light of the Commission's approval of the alternative deferred accounting treatment for the Merwin Project costs, the Company withdrew its proposed tariff in Docket UE-140617, on May 30, 2014. Pacific Power now proposes recovery of $1.7 million in deferred costs related to the Merwin Project over one year in Schedule 92. This brings the total request for recovery via Schedule 92 to $6.6 million.

14 The Commission convened a prehearing conference in the consolidated proceedings at Olympia, on May 30, 2014. The Commission held public comment hearings in Yakima on September 25, 2014, and in Walla Walla on September 26, 2014. On various dates established in its procedural schedule, the Commission accepted prefiled testimony and exhibits from the Company, the Staff, and other parties. The Commission held evidentiary hearings in Olympia on December 16-19, 2014, to receive evidence from the parties and to allow them an opportunity to conduct cross-examination of witnesses who prefiled testimony. These hearings also gave the Commission an opportunity to conduct inquiry from the bench.

15 During the public comment hearings, the Commission received into the record oral comments and exhibits from 20 members of the public. The Commission also accepted numerous written comments from members of the public.[9] The final transcript in this proceeding includes 663 pages and reflects the admission of prefiled testimony and exhibits sponsored by 30 witnesses. The documentary record includes 377 exhibits.

16 The parties filed their Initial Briefs on January 22, 2015, and Reply Briefs on February 3, 2015. The final record, including public comment and detailed evidence concerning Pacific Power's revenue requirements and other issues, was closed on February 18, 2015, following receipt of several responses to Commission bench requests made during and after the hearing. We have considered the parties' arguments and reviewed the full record. Our discussion and determination of the issues follows below.

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[9] These comments are identified in the formal record as Exhibit B-1.

II. Ratemaking Authority and Practice

17 The Commission's general powers and duties set forth in RCW 80.01.040 include its responsibility to:

> Regulate in the public interest, as provided by the public service laws, the rates, services, facilities, and practices of all persons engaging within this state in the business of supplying any utility service or commodity to the public for compensation.[10]

When a utility subject to the Commission's jurisdiction, such as Pacific Power, files tariff sheets that would effect a change in the rates, terms, or conditions of its service to customers in Washington that is a "general rate proceeding" under WAC 480-07-505. In such cases, the Commission typically exercises its authority under RCW 80.04.130 (1) to suspend the effectiveness of the filing for up to 10 months and set the matter for hearing.[11]

18 The Commission's responsibility in general rate case proceedings is to determine an appropriate balance between the needs of the public to have safe and reliable electric services at reasonable rates, and the financial ability of the utility to provide such services on an ongoing basis. In statutory parlance, whenever the Commission finds, after a hearing, that a utilities rates are "unjust, unreasonable, unjustly discriminatory or unduly preferential," or that its rates "are insufficient to yield a reasonable compensation" to the utility, the Commission must "determine the just, reasonable, or sufficient rates" to be effective prospectively.[12] Table 1 illustrates that the parties in this proceeding hold very different ideas of what amount of revenue increase, or decrease, will produce rates that strike this balance.

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[10] RCW 80.01.040 (3).

[11] *See supra* ¶ 11.

[12] RCW 80.28.020.

TABLE 1
Proposed Total Adjustments to Annual Revenue Requirement

	As-Filed	Response	Rebuttal/Cross	Per Briefs
PP&L	$27,201,266 (8.5%)		$31,938,957 (9.9%)	$30,398,178 (9.5%)
Staff		$7,740,733 (2.41%)		$7,955,874 (2.47%)
Public Counsel		$1,126,556 (0.35%)		$1,126,556 (0.35%)
Boise White Paper		$(2,736,141) (0.85%)		$3,344,138 (1.04%)

The range of possible outcomes most likely encompasses a somewhat narrower range of reasonable outcomes. We must determine solely on the record of this proceeding the reasonable range and what revenue requirement within the reasonable range results in rates that are just, reasonable, and sufficient.[13]

19 Although "not bound to the use of any single formula or combination of formulae in determining rates"[14] we must find on the basis of the record three things:

[13] The seminal cases establishing the legal principles for utility rate regulation that have continued to guide ratemaking practice for 75 years refer to the "just and reasonable standard," leaving "sufficient" as an implied constitutional condition for just and reasonable rates from the utility company's perspective. Thus, in *Fed. Power Comm 'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 602-03 (1944), the Supreme Court stated that there are various "permissible ways in which any rate base on which the return is computed might be arrived at," and it is constitutionally sound so long as the "result reached" by the regulator is just and reasonable from the company viewpoint. *See also Fed. Power Comm'n v. Nat. Gas Pipeline Co.,* 315 U.S. 575, 586 (1942) ("[T]he just and reasonable standard . . . coincides with the applicable constitutional standards." The Court reaffirmed the "teachings of Hope" in *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310 (1989).

[14] *Hope*, 320 U.S. at 602. Expanding on this point, the Court said:

> Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important.

Id. This language, embodying the familiar "end result" test, is universally recognized as an important guiding principle in utility ratemaking throughout the United States. In a later case, the

- What levels of prudently incurred expenses the Company will experience during the rate year.[15]
- The amount of the Company's "rate base." [16]
- An appropriate rate of return on that rate base.

The Washington Supreme Court explained this rate-making formula as follows:

> In order to control aggregate revenue and set maximum rates, regulatory commissions such as the WUTC commonly use and apply the following equation:
>
> $$R = O + B(r)$$

Supreme Court embraced the end result test and recognized a "zone of reasonableness" within which rates approved by a regulatory authority may not be set aside. *In re Permian Basin Area Rate Cases*, 390 U.S. 747, 767 (1968). The Washington Supreme Court, more recently yet, made clear the applicability of these principles in cases before this Commission:

> While modernly a reviewing court's role in this State is delineated by the administrative procedure act . . . *Hope Natural Gas* and *Permian Basin* continue to provide guidance in the judicial review of rate cases; and it remains the law that courts are not at liberty to substitute their judgment for that of the Commission.

People's Org. for Wash. Energy Res. v. Utils. & Transp. Comm'n, 104 Wn. 2d 798, 812 (1985) (*POWER*).

[15] The rate year begins on the date the Commission authorizes or allows new rates to become effective. This may be as early as 30 days after a company files revised tariff sheets. *See* RCW 80.04. Typically, however, when a company files a general rate case, the as-filed tariff sheets are suspended for a period of up to 10 months after their stated effective date and the benchmark effective date for revised rates to become effective is the day after the last day of the statutory suspension period. In this case, the benchmark effective date is April 1, 2015. Thus, the anticipated rate year in this case is April 1, 2015, through March 31, 2016.

[16] Reduced to a simple definition, rate base is the Commission-approved level of PSE's investment in facilities plus the cash, or "working capital" supplied by investors that is used to fund the Company's day-to-day operations. The Commission follows the original cost less depreciation method when determining the value of a utility's property that is used and useful in providing service to customers. *POWER*, 104 Wn.2d at 828.

In this equation,

> R is the utility's allowed revenue requirement;
> O is its operating expenses;
> B is its rate base; and
> r is the rate of return allowed on its rate base.

> Although regulatory agencies, courts and text writers may vary these symbols and notations somewhat, this basic equation is the one which has evolved over the past century of public utility regulation in this country and is the one commonly accepted and used.[17]

The sum of the two figures – expenses and return on rate base – constitutes the Company's revenue requirement that we approve for recovery in rates. This basic formula is a simple expression of a complex, highly technical, and formal process.[18] The goal for the Commission in conducting this process is to reach an end result that allows the Company to recover the costs of its investments in infrastructure, repay its lenders, and provide an opportunity for the Company to earn a reasonable return, some of which may be distributed to its equity investors in the form of dividends.[19] Thus, we determine just and reasonable rates that are safely above the constitutional minimum and that afford the utility recovery of its operating expenses and both the return of its prudent investments through depreciation expense and an opportunity for its investors to earn a fair return on their investments that are used and useful for providing utility services.

20 States are free, within broad limits, to decide what ratemaking methodology best meets their needs in balancing the interests of the utility and the public it serves.[20] Washington ratemaking practice is based on a hybrid test year that uses historic data

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[17] *Id.* at 809.

[18] *See id.* at 807-09 (describing ratemaking principles and process).

[19] Regulatory agencies need not, and do not guarantee that a utility will recover its authorized return. "A regulated [utility] has no constitutional right to a profit" and regulation does not even ensure that the regulated company will produce net revenues. *Jersey Cent. Power & Light Co. v. FERC,* 810 F.2d 1168, 1180-81 (D.C. Cir. 1987) (*en banc*); *see also Nat. Gas Pipeline Co., 315 U.S.* at 590. Indeed, a rate is not necessarily unlawful even if it results in the company operating at a loss so long as it gave the company the opportunity to operate at a profit when approved.

[20] *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 315-16 (1989).

as a starting point for analysis. While this distinguishes Washington practice from the future test year approach used to set Pacific Power's rates in Utah, Oregon, and California, in point of fact, Washington practice is quite forward looking. Although we are often recognized as a historic test year state, it is more accurate to say that the Commission relies on a "modified" or "hybrid" test year.[21] The Commission, for example:

- Approves pro-forma adjustments to test-year costs when the adjustments are adequately supported.
- Allows calculation of base power costs based on costs projected for the rate year based on data contemporaneous with the end of a general rate case (*i.e.,* at the beginning of the rate year).
- Accepts filings for updates to power costs "between rate cases." For PSE, it allows for expedited power-cost-only rate cases (PCORCs) that adjust rates to reflect addition of new power resources, or fuels costs, without requiring a comprehensive rate proceeding.
- Allows new generation plant in rate base even when the new facilities are placed in service subsequent to the end of the test period.
- Has approved end-of-period rate base when this is shown to be appropriate.
- Has allowed CWIP (Construction Work in Progress) in rate base.
- Has approved hypothetical capital structures to improve a utility's weakened financial condition.

21 With these principles in mind, we turn in the sections following below to consideration of the contested issues, starting with proposed *pro forma* adjustments. We resolve first disputes concerning general wages and retirement benefits, insurance expense, and the Company's proposal to apply an escalation factor to Operating & Maintenance (O&M) expenses apart from labor- and power-related O&M expenses.

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[21] *See* Lowry, Mark Newton, Hovde, David Getachew, Lullit' Makos, Matt, Edison Electric Institute, *Forward Test Years for U.S. Electric Utilities*, August 2010**.**

22 Pacific Power's net power costs are a principal driver of its request for increased revenue with power cost issues accounting for nearly 46 percent of the total amount of the increase the Company proposes. This includes increases in updated net power costs reflected in the Company's rebuttal testimony, which are driven principally by post-test period increases in the costs of coal to fuel the Company's Colstrip and Jim Bridger power plants. These updates added an additional $5.4 million to Pacific Power's overall revenue request.[22]

23 In the context of this discussion, we take up Staff's proposed Power Cost Adjustment Mechanism (PCAM) and Pacific Power's proposed Renewable Resource Tracking Mechanism (RRTM). Once we determine the "O" (*i.e.,* operating expense) and "B" (*i.e.,* rate base) factors in our ratemaking equation, we complete the revenue requirement portion of our discussion with determination of the Company's cost of capital, the "r" or rate of return that is multiplied by the rate base in the basic rate equation.

24 To determine "r", we develop a weighted cost of capital for the Company based on a capital structure that balances safety and economy. Capital structure, and particularly the equity ratio and cost of equity, materially impacts the price customers pay for service. Due to the relative difference between the higher cost of equity and the lower cost of debt, a capital structure with relatively more debt and less equity may result in a lower overall cost of capital.[23] This results in lower rates for customers. This is commonly referred to as "economy." On the other hand, a capital structure with relatively more equity and less debt may result in a higher overall cost of capital and higher rates for customers, but enhanced financial integrity. This is commonly referred to as "safety."[24]

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[22] Duvall, Exh. No. GND-4T at 8:5-9.

[23] The use of equity versus debt capital is also significant because of the impact of federal income taxes in the determination of a utility's revenue requirement. The additional revenue necessary to pay a higher return on equity must be supported by additional revenue from customers to pay Federal income taxes. On the other hand, when financing with debt the utility can deduct its interest expense resulting in a reduction in the utility's costs and revenue requirement, benefiting both customers and the utility.

[24] This simplified relationship assumes that the cost of equity does not vary with the equity ratio. In fact, the cost of equity may decline as the equity ratio increases because financial risk declines. *See* 1 Leonard Saul Goodman, *The Process of Ratemaking* 642-43 (1998).

25 Taking the last step to determine the specific base rates various types of customers will pay, we address Pacific Power's cost of service study, rate spread and rate design. In doing so, we establish how Pacific Power's costs will be allocated to different classes of customers, such as residential, commercial and industrial, and the means by which those costs will be recovered from each customer class in base rates and rates tied to levels of use. In this case, the Company proposes, among other things, to recover significant additional fixed costs in basic charges resulting in a nearly 80 percent increase to the residential basic charge. Staff also proposes a large increase to this charge, and proposes changes to the Company's residential volumetric block rates.

26 We address, too, the Company's programs that are designed to assist low-income customers that Pacific Power serves in Washington. The Company proposes to increase the number of participants, to increase the participant benefit by two times whatever residential rate increase is approved, and to reduce the monthly customer charge to qualifying customers. These proposals are consistent with a currently effective five-year plan the Commission approved previously.

27 Finally, we consider four related matters, three of which were initiated in separate dockets that are now consolidated into this general rate proceeding. These include two proposals by Pacific Power to recover deferred power costs (*i.e.,* costs attributed to an outage at the Colstrip power plant in Docket UE-131384, and to low-hydro conditions projected for 2014 in Docket UE-140094) and the Merwin Project deferral (*i.e.,* Docket UE-140617). The fourth matter concerns a deferral of the difference between depreciation rates approved in Docket UE-130052 and the depreciation rates reflected in the Company's 2013 GRC in Docket UE-130043.[25] It is appropriate to consider these matters separately in light of Pacific Power's proposed use of deferred accounting for the power costs and a separate tariff rider (*i.e.,* Schedule 92) to amortize fully any allowed costs over one year.

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[25] The Commission, in Docket UE-132350, approved deferral of the resulting reduction in depreciation expense.

III. Discussion and Decisions

A. Introduction

28 This is Pacific Power's ninth general rate case in Washington since 2003.[26] But for one case, all have resulted in rate increases for the Company.[27]

29 The Commission entered its Final Order in Docket UE-130043, the Company's most recently completed general rate case, on December 4, 2013.[28] In that order the Commission:

- Authorized rates that would provide the Company an opportunity to recover an additional $16.7 million in revenue during the rate year, relative to its previously authorized rates.

- Rejected Pacific Power's proposed revisions to the West Control Area inter-jurisdictional cost allocation methodology in effect since being initially authorized in June 2007, including the Company's proposal to change the situs allocation of the cost of Qualifying Facilities (QFs) under the Public Utilities Regulatory Policies Act (PURPA).[29]

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[26] The prior dockets are UE-032065 (2003/2004), UE-050684 (2005/2006), UE-061546 (2006/2007), UE-080220 (2008), UE-090205 (2009), UE-100749 (2010/2011), UE-111190 (2011/2012), and UE-130043 (2013/2014).

[27] The Commission rejected the Company's 2005 tariff filing. *Utilities & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light*, Docket UE-050684, Order 04 (April 17, 2006). The Commission's order in Docket UE-050684 is significant in the context of this case because it rejected the use of the Revised Protocol inter-jurisdictional cost allocation methodology in this state, rejected a decoupling proposal by the Company and Natural Resource Defense Council because it lacked necessary operational details and was otherwise insufficiently developed, and rejected the Company' proposed Power Cost Adjustment Mechanism because it failed to focus on short-term costs subject to market volatility or other extraordinary events beyond the Company's control, included costs for new generation, and failed to balance adequately through the use of dead bands and sharing bands the shared risks and benefits borne by shareholders and ratepayers.

[28] *Utilities & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light*, Docket UE-130043, Order 05 (December 4, 2013).

[29] Pub.L. 95–617, 92 Stat. 3117 (enacted November 9, 1978).

- Approved Pacific Power's use of End of Period (EOP) rate base in lieu of a long and still preferred approach that uses the average of monthly averages (AMA) to determine rate base.

- Approved various additions to rate base, including the *pro forma* costs of certain production related facilities with post-test period in-service dates as late as 11 months after the end of the test year.

- Approved a capital structure including 49.10 percent equity, 50.62 percent debt, and 0.28 percent preferred stock, with a 9.5 percent return on equity, a 5.29 percent cost of debt, and a 5.43 cost of preferred stock, resulting in an overall rate of return of 7.36 percent.

- Rejected the Company's proposed PCAM largely because the proposed mechanism was not designed in accordance with clear, prior direction from the Commission concerning the required elements for a PCAM.

Pacific Power filed a petition for judicial review that is now pending before Division II of the Washington state Court of Appeals.[30] The Company's appeal challenges the Commission's determination of two issues in Docket UE-130043:

- The decision to continue using the situs allocation methodology for QF costs as originally proposed by Pacific Power in 2006 and adopted by the Commission in 2007.[31]

- The decision to continue using a hypothetical capital structure the Commission has left unchanged through several Pacific Power GRCs, again finding it to balance safety and economy more appropriately than would Pacific Power's proposed use of its parent corporation's "actual" capital structure.[32]

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[30] *PacifiCorp d/b/a Pacific Power & Light Company* v. *Washington Utilities and Transportation Commission*, *Public Counsel Division of the Washington State Office of the Attorney General* and, *Packaging Corporation of America f/k/a Boise White Paper, L.L.C.*, No. 46009-2-II.

[31] *See Utilities & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light*, Dockets UE-061546 and UE-060817 (consolidated), Order 08 ¶¶ 43-58, (June 21, 2007)

[32] Neither Pacific Power nor its parent, PacifiCorp, are publicly listed or traded on the stock exchanges. It thus is something of a stretch to conceive of either corporation having an "actual" capital structure. PacifiCorp's capital structure is controlled entirely by its owner, Berkshire

30 Despite the pendency of its appeal of these two, highly significant issues, Pacific Power nevertheless filed this case on May 1, 2014, only five months after the Commission's Final Order in Docket UE-130043. In this filing, the Company makes the same arguments rejected by the Commission in the prior case, and again asks us to abandon the situs allocation methodology for QF costs and urges adjustment of the Company's capital structure balance between safety and economy in favor of Pacific Power by using PacifiCorp's "actual" capital structure.

B. *Pro Forma* Expense Adjustments

1. General Wage Increase - *Pro Forma* Expense and Pension Expense (Adjustment 4.3)

31 Pacific Power proposes to include in Washington rates a post-test year wage increase, "using known and measurable increases that have occurred or are expected to occur through March 2016."[33] The Company also proposes to apply the adjusted wage levels to its average full-time-equivalent (FTE) employee levels during the historical test year, with no post-test year adjustment, to determine labor expenses and to include in rates pension and other post-employment benefit (OPEB) expenses.[34]

32 Public Counsel argues that the Company's post-test year wage increase proposal, extending "27 months beyond the end of the test-period," is essentially equivalent to the use of a future test period and recommends limiting the post-test year wage increases to those increases in effect by December 31, 2014.[35] Public Counsel argues in addition that the Company's post-test year FTE count should be adjusted to reflect a continuing trend of reduced FTEs over several years and through the pendency of the hearing.

Hathaway Energy, presumably to benefit BHE. This fact is evidenced in this case by Mr. Dalley's and Mr. Williams' testimony that PacifiCorp, after retaining 100 percent of its earnings since the time of its acquisition by BHE, recently began providing significant dividends up to BHE. While retaining earnings and other practices have inflated the level of equity on PacifiCorp's books since the time it was acquired by BHE, dividend payments will reduce the amount of equity on the Company's books. According to Mr. Williams, the corporate plan is to reduce the equity share at PacifiCorp to "about 50 percent." *See* TR. 326:24-328:7.

[33] Pacific Power Initial Brief ¶ 129.

[34] *Id.*

[35] Public Counsel Initial Brief ¶¶ 54-55; Ramas, Exh. No. DMR-1CTr at 20:20-22.

33 Pacific Power argues that its "proposal is consistent with Commission precedent approving similar *pro forma* adjustments for the Company's wage and salary expenses" citing the Commission's final order in the Company's 2010/2011 general rate case.[36] In Docket UE-100749, however, the Company's proposed *pro forma* adjustment to the test year ended December 31, 2009, was based on actual changes 12 months out, through December 31, 2010, not 27 months. Union labor cost increases were adjusted using contract agreements whereas non-union and exempt employee adjustments were based on actual labor cost increases effective January 2009 and 2010.[37] By the time of the hearing, in late January 2011, these costs were fully known and measurable and, indeed, there was no opposition argument to the level of the *pro forma* wage increases.[38] The parties' opposition was based on their argument that the adjustment "should be disallowed because the Company did not consider all relevant factors including whether there are corresponding offsets to the wage increases."[39]

34 Public Counsel acknowledges that the Commission has allowed post-test year salary and wage increases as *pro forma* adjustments to test year costs, if they are known and measurable and occur within 12 months after the end of the test year.[40] Public Counsel argues that "this approach is more than reasonable, and should be adhered to again in this case" which would limit the *pro forma* adjustment to wages to known and measurable costs through December 31, 2014.[41]

35 Public Counsel argues in addition that the Company's proposal essentially is to base wage and salary levels on a future test year for the 12 months ending March 31, 2016, which creates a distortion of the alignment between revenue, investment, and expense, violating the matching principle. Public Counsel contends that it is "particularly unfair to include costs from such a distant future period, given the

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[36] Pacific Power Initial Brief ¶ 130 (citing *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶¶ 226-235 (Mar. 24, 2011)).

[37] *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 226 (Mar. 24, 2011).

[38] *See Id.* ¶ 228.

[39] *Id.* ¶ 227.

[40] Public Counsel Initial Brief ¶ 55 (citing Ramas, Exh. No. DMR-1CTr at 20:8-18.)

[41] *Id.*

evidence in the record that PacifiCorp's employee count has been declining for the past 3½ years."[42]

36 Elaborating on this last point, Public Counsel states that while Pacific Power's adjusted test year labor costs are based on the average number of employees employed by the Company during the test year ending December 31, 2013, the full time equivalent (FTE) employee count for Pacific Power declined significantly during the test year and continued to decline measurably through October 2014, just prior to the evidentiary hearing in this case (*i.e.,* December 16-19, 2014). Providing details, Public Counsel says that:

> During the test year, PacifiCorp's employee count declined by 115.5 employees. Six months later, by June 2014, the employee count had declined by another 27 FTEs, such that the actual employee level was 66.5 FTE lower, or 1.24% below the average count for the test year upon which Pacific Power based its labor costs. Additional data provided to Public Counsel after the filing of Pacific Power rebuttal shows (sic) that FTE counts continued to decline every month after June 2014, until November, just one month before the hearing.[43]

37 Pacific Power argues that "[t]he Company demonstrated that the reductions in staffing it is currently experiencing are temporary."[44] The Company, however, offers no cite to the record pointing us to its demonstration of this asserted fact. Mr. Stuver's testimony, adopting that of Mr. Wilson in this case, is strikingly similar to Mr. Wilson's testimony in Docket UE-100749. In both cases, the Company's witnesses:

- Acknowledge that evidence presented by Public Counsel shows reduced levels of employees through the test period.

- Claim these reductions are temporary.

- Testify that Pacific Power requires a basic minimum level of staffing to ensure that its business operates smoothly.

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[42] *Id.* ¶ 54.

[43] *Id.* ¶ 56. We note that parties and the Commission, in prior orders, sometimes refer to Pacific Power as PacifiCorp.

[44] Pacific Power Initial Brief ¶ 131.

- Testify that the Company is actively recruiting to fill the vacant positions.

Mr. Stuver's testimony in this case nowhere rebuts that the Company has experienced a net reduction in FTE employees over a significant period of time.

38 Finally, Pacific Power argues that its updated business plan in the fall of 2014 shows 5,377 employees for the end of 2015. The Company states in addition that:

> The test period average FTE complement of 5,375 closely approximates the *budgeted* FTE complement. In addition, the Company uses contract employees to backfill vacancies, and the expenses associated with retaining contract employees are roughly comparable to the expenses of the FTE employees.[45] Public Counsel's proposal would prevent the Company from recovering expenses that are likely to be incurred regardless of whether the Company permanently fills all the current FTE employee vacancies.[46]

39 Turning to Pension Expense and OPEB, Public Counsel argues that Pacific Power's pension costs have declined significantly in 2014 since the amount recorded in the Company's books for the 2013 test year, by an amount of $16.8 million.[47] Similarly, the Company's OPEB costs declined between the 2013 test year and 2014, from $2.7 million to $485,000, a reduction of over $2.1 million.[48] Both the 2014 pension expense and the 2014 OPEB expense are based on the 2014 actuarial assumptions Pacific Power selected at the end of 2013, and upon the actual 2013 plan experience. Ms. Ramas testifies for Public Counsel that:

> In the Pacific Power Response to Public Counsel Data Request No. 66, the Company provided the most recent pension actuarial report from the actuarial firm it uses, Towers Watson, dated January 2014. At page 4 of the actuarial report, Towers Watson describes the "significant reasons" for the reduction in the net periodic cost, as well as the

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[45] *Id.* at 496:15-25, 497:1.

[46] Pacific Power Initial Brief ¶ 132 (emphasis added; internal citations to Mr. Stuver's testimony omitted).

[47] Public Counsel Initial Brief ¶ 60.

[48] *Id.* ¶ 65.

> improvement in the funded position, as caused by four factors. These include: 1) the return on the fair value of plan assets was greater than expected improving the funded position; 2) the return on the market-related value of plan assets was greater than expected reducing the pension cost; 3) contributions to the plan during 2013 reduced the net periodic costs and improved the funded position; and 4) the discount rate (which is one of the actuarial assumptions) increased 75 basis points reducing the net periodic cost and improving the funded position.[49]

Thus, Public Counsel says, these reductions are known and measurable changes that reflect the impacts of actuarial assumptions that were selected at the end of the test year.[50]

40 Pacific Power argues that Public Counsel's proposed adjustment to Pension and OPEB expenses violates the matching principle by focusing on one element of labor expense while ignoring other elements of labor expense, such as increased health care costs, that may offset the reduction. The Company's rebuttal testimony, however, includes no showing that this is so. Nor is there other evidence in the record that demonstrates the Company's point. Instead of presenting evidence, Pacific Power asks us to rely in this case on its argument that:

> The Company's wage and labor proposals in this case are consistent with its prior rate case filings, in which pension and OPEB expenses, as well as other labor-related expenses, are based on the historical test year. In the 2010 case, the Commission approved the Company's *pro forma* wage adjustment while noting the Company "did not adjust changes in workforce levels, employee benefits and incentives, or pensions."[51]

41 *Commission Determination:* Pacific Power's approach to adjusting wages, contrary to the Company's claim, is not "consistent with Commission precedent." We reject it here.

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[49] Ramas, Exh. No. DMR-1CTr at 26:8-19.

[50] Public Counsel Initial Brief ¶ 62 (citing *id.*)

[51] *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 226 (Mar. 25, 2011).

42 Addressing the issue of employment levels in Docket UE-100749, the Commission said:

> We do not lightly reject the Joint Parties argument that all wage increases in 2010 should be eliminated because workforce reductions can offset any increases. . . . However, there are two reasons why, in this case, we cannot make the requested adjustments.
>
> First, although it appears that workforce levels are lower, there is insufficient evidence in this record to quantify a potential offset to the revenue requirement. No witness of the Joint Parties offered an adjustment for us to evaluate or for the other parties to critique. Accordingly, we would be creating an adjustment out of an imprecise record on this point, a task we are reluctant in this instance to undertake.
>
> Second, even if the proposed adjustment could be precisely quantified, the Joint Parties do not demonstrate that these are permanent work force reductions. The Company persuasively countered that the reduction in workforce levels is temporary and the slight downward trend is due to a hiring lag.[52]

Neither of these deficiencies is present in this case. Ms. Ramas quantifies the impact of the test period and post test period reductions in FTEs. The record demonstrates that the reductions in workforce reflect a continuing trend over several years. Indeed, the benefit of hindsight, coupled with evidence in this case, shows that Pacific Power's assertion in 2010 that declining FTEs represented nothing more than a temporary condition proved not to be accurate.

43 In 2010, the Company's employee count average during the test year ending December 31, 2009, was 5,651.[53] The actual count as of December 31, 2010, apparently was 5,586.[54] By the time of this case, these figures stood at 5,375 for the average test year FTE count, and 5,308 as of December 31, 2014. Thus, Pacific

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[52] *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶¶ 230-32 (Mar. 24, 2011).

[53] *Id.* ¶ 232, n. 334.

[54] *Id.*

Power today has nearly 300 fewer employees than it did in 2009 and 2010, roughly a 5 percent reduction in the Company's workforce over a period of six years. Evidence in this case shows definitively that this long-term trend continued during the 2013 test year and during the pendency of this case through at least June 2014.[55] Even so, Pacific Power argues we should adjust test year wages using forecasted wage increases that extend out to March 2016, 27 months beyond the end of the test year, without making any adjustment for employee counts.

44 The Company's argument that its budgeted FTEs as of fall 2014 closely approximate its test-year average FTEs does not justify using the test year average as Pacific Power proposes. As Pacific Power is fully aware, Washington uses a hybrid test year approach that allows *pro forma* adjustments only for known and measurable changes –not budgeted or projected changes– that occur, generally within a reasonable time after the end of the test year and, with some exceptions,[56] almost never more than 12 months after the end of the test year.[57]

45 On the subjects of Pension Expense and OPEB, we begin with the observation that each case must be decided exclusively on its own record.[58] It is not at all clear from the order in Docket UE-100749 that the Commission's determination of these issues in the Company's favor was firmly grounded in the record of that proceeding. Indeed, we cannot discern today exactly upon what basis the Commission decided the matter as it did. This, however, is of no consequence to us in this proceeding. What

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[55] *See* Revised Exh. No. DKS-3CX (Public Counsel cross-examination exhibit for Company witness Mr. Stuver).

[56] *See supra* ¶ 18. The only regular exception the Commission makes is for power costs, which are a very significant part of electric utility expense and which are updated with a very high level of analytical rigor and readily available market data concerning fuel costs, and other costs.

[57] We note that it is even exceptional for the Commission to allow *pro forma* adjustments beyond a few months after the end of the test year. The Commission has relaxed this careful approach somewhat during recent years, risking violation of the matching principle, in an effort to address concerns that regulatory lag has been increasingly problematic during a period of unusually high capital investment. The Commission also has used other approaches, such as use of EOP rate base instead of the preferred AMA approach, and allowance of attrition adjustments, to address this problem. Nevertheless, companies we regulate continue to file regularly for general rate increases. Pacific Power, for example, has filed one general rate case after another, year after year, as exemplified by its filing of this case only five months after the Commission authorized rate increases in Docket UE-130043 in 2013.

[58] RCW 34.05.

matters is that Pacific Power offers nothing in the way of evidentiary support for its position in this case. Moreover, the Company's arguments are unpersuasive considering that the Company proposes *pro forma* adjustments far beyond the end of the test year for the components of its labor costs that result in a higher revenue requirement, but argues against recognizing any known and measurable offsets for the corresponding post-test year period.

46 We accordingly accept Public Counsel's recommendation, based on Ms. Ramas' analysis, to reduce Pacific Power's pension expense by $16.8 million on a Company basis. According to Ms. Ramas, after removing the portion allocated to capital and non-utility, the impact is a reduction of $11.7 million on a Company basis, and $761,547 on a Washington-jurisdictional basis.[59] In addition, we accept Public Counsel's recommendation that OPEB expense should be reduced by $2.21 million. After removal of amounts allocated to capital and non-utility, the reduction is $1.5 million on a total Company basis, and $100,686 for Washington.[60]

2. Insurance Expense (Adjustment 4.7)

47 Pacific Power's adjusted test year liability insurance expense is based on a six-year average of the liability expense accruals the Company booked from 2008 through the end of the test year. The Company voluntarily removed several accruals booked in 2012 and 2013, as shown in in the table below, resulting in a six-year average of $9,402,352 on a Company basis, with $644,437 allocated to Washington. The six-year rolling average approach is intended to normalize fluctuations in insurance expenses that occur year-over-year.[61] The Commission approved this method as part of a settlement in Pacific Power's 2011 GRC and in the Company's 2013 GRC where it was not contested.[62]

48 Staff accepts the use of a six-year rolling average, but proposes to replace the Company's 2012 insurance year net expense level of $30,859,248 with the 2007 insurance year expense level of $10,087,289, for purposes of calculating the six year

[59] Ramas, Exh. No. DMR-1CTr at 27 (referencing Schedule 9).

[60] *Id.* at 28:14-20 (referencing Schedule 10).

[61] Siores, Exh. No. NCS-10T, at 8:18-20.

[62] *WUTC v. PacifiCorp*, Docket UE-111190, Settlement Stipulation at 5 (Feb. 21, 2012). *See WUTC v. PacifiCorp*, Docket UE-130043, Revised Final Issues List (Aug. 23, 2013)

average.[63] Mr. Ball testifies that the Company's actual 2012 insurance level is not representative of a normal level of expense that can be expected to occur during the rate year. Indeed, he observes, it is approximately 10 times higher than the 2011 expense level and three times higher than the next highest expense level, the amount reflected for 2007.[64] Staff's adjustment reduces the Company's proposed adjustment by $248,323 on a Washington basis.

49 Public Counsel recommends removing $20 million in reserves from the Company's 2012 liability and property damage expenses.[65] Ms. Ramas testifies that Pacific Power, in response to discovery, explained that the net expense shown for 2012 is significantly higher than the amounts for the remaining years because the Company booked "increased reserves required for certain fires, an oil spill, personal injury claims, and other injuries and damages claims that occurred in 2012."[66] Based on her examination of data from 2006 forward, Ms. Ramas agrees with Staff's assessment and gives her opinion that "the expense accrual recorded in 2012 is an anomaly."[67]

50 In rebuttal, the Company argues Public Counsel and Staff are subjectively and arbitrarily removing one year simply because it is "too high".[68] Responding to Public Counsel's statement that the 2012 insurance expenses accrued on a Company-wide basis are in part allocated to Washington because of the System Overhead allocation factor in the West Control Area (WCA) inter-jurisdictional cost allocation methodology, the Company reasserts the appropriateness of allocating insurance expense using this allocation factor.[69] The Company, however, does not provide a justification for the increased reserve requirements for the specific items identified in Ms. Ramas' confidential testimony for Public Counsel or counter Staff's characterization of the 2012 level as non-representative for use in the six year average for test-year purposes.

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[63] Ball, Exh. No. JLB-1T, at 14:1-3, 15-17.

[64] *Id*. at 14:7-14.

[65] Ramas, Exh. No. DMR-1CT, at 34:1-2.

[66] *Id.* at 32:7-15 (quoting from Pacific Power Response to Public Counsel Data Request No. 78).

[67] *Id.* at 32:19-22.

[68] Siores, Exh. No. NCS-10T, at 8:6-17.

[69] Siores, Exh. No. NCS-1T, at 9:1-3. For a brief history of the WCA methodology, *see infra* ¶ 69, n. 94.

51 Asked by Public Counsel during discovery to explain why Pacific Power excluded $16 million in potential liability from its 2012 insurance costs, the Company responded that "these reserve amounts were excluded from the calculation of the average cost because PacifiCorp intends to seek insurance recovery when these liability claims are fully settled."[70] Mr. Stuver initially affirmed this rationale and testified that the incident in question, the "Wood Hollow fire," remained subject at the time of hearing to "ongoing mediation and settlements with the Wood Hollow claimants."[71] Mr. Stuver also acknowledged during cross-examination that liability has not yet been established for the claims accrued on the Company books and contested by Public Counsel.[72] These matters, too, were unresolved in terms of what final liability the Company might incur and both were subject to ongoing settlement negotiations and mediation.[73] In these ways, as developed through Mr. Stuver's cross-examination, these claims are indistinguishable from the Wood Hollow fire claims that the Company excluded from insurance expense for 2012 because the incident is the subject of "ongoing litigation which makes the total costs attributable to this fire not known and measurable at this time."[74] Rather than providing a satisfactory rationale as to why the additional claims, also still in dispute, were not likewise removed from the liability expense adjustment because they are not known and measurable, Mr. Stuver retreated from the rationale he previously affirmed with respect to the Wood Hollow fire and expressed his opinion that all of these claims were known and measurable and should be included in calculating the six year average.[75]

52 *Commission Determination:* The purpose of the six-year average as a replacement for the test-year booked insurance costs is to provide a normalized level of expense, which the parties agree is a proper way to determine this expense for inclusion in

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[70] Exh. NCS-21-CX. The Commission approved the WCA approach in 2007. *See WUTC v. PacifiCorp*, Dockets UE-061546 and UE-060817 (consolidated), Order 08, ¶¶ 56-57 (June 21, 2007).

[71] Stuver, TR. 483:7-8.

[72] Stuver, TR. 483:1-6. *See also* Exh. No. NCS-22 C CX, a confidential exhibit that provides details concerning three incidents during 2012, including the two Public Counsel contests, that show them to be unresolved and subject to settlement negotiations.

[73] *Id.*

[74] Exh. No. NCS-26CX; Stuver, TR. 481:3-20.

[75] Stuver, TR. 483:18-25.

rates. The use of averages of brief periods of years, however, is not entirely straightforward when the data reflect extraordinarily high costs such as the insurance reserves set aside in 2012. The extreme variance in costs exhibited by the Company's 2012 expense relative to the other years in the record is sufficient in itself to justify the sort of adjustment Staff proposes.

53 In this case, however, Public Counsel developed evidence that provides an even a more compelling reason to make adjustments. As developed by Public Counsel, the record shows that Pacific Power itself removed from the six-year average significant reserves booked for incidents that remain subject to litigation and in the process of settlement negotiations because the costs cannot be considered known and measurable. Yet, the Company included reserves for other incidents that also remain unresolved without satisfactorily explaining why we should consider the costs of these matters to be known and measurable. Not only are these costs not presently known and measurable, it may turn out in the final analysis that the Company was negligent or even grossly negligent with respect to the underlying incidents. This could give the Commission reason not to allow the costs in rates for recovery even if the level of costs is firmly established.

54 Considering this uncertainty, we find it appropriate to accept Public Counsel's recommendation to exclude $20 million in reserves from insurance expense for the two relevant events. We accept Public Counsel's proposed adjustment for a $20 million reduction in 2012 insurance expense. According to Ms. Ramas, this reduces the average expense calculated by the Company by $3,333,333. We determine accordingly that Pacific Power's test year insurance expense should be reduced by $3,333,333 on a total Company basis and by $228,467 on a Washington-allocated basis.

3. IHS Global Insight's Escalation Factors (Adjustment 4.13 - Operations & Maintenance (O&M) Expenses other than labor and power related O&M)

55 Pacific Power, borrowing from practices accepted in two of its three jurisdictions that use a future test year approach to ratemaking,[76] proposes to escalate its non-labor

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[76] Utah and Oregon have approved the use of these escalation factors for forecasting future test period costs. Wyoming, also a state that uses a future test year, has rejected their use. *See* Boise White Paper Initial Brief ¶ 62 (citing *Re Application of Rocky Mountain Power for Approval of a*

Operations & Maintenance and Administrative & General expenses using proprietary indices prepared by IHS Global Insight.[77] These are not indices prepared with specific reference to Pacific Power. They rely on data from the U.S. utility industry generally. IHS Global Insight assesses electric utility costs for materials and services (excluding labor) and develops escalation factors broken out by FERC Uniform System of Accounts functional subcategory.[78] The individual indices are then combined into broader indices representing operation, maintenance, or total operation and maintenance expenses.[79] The Company proposes applying the IHS Global Insights indices, by FERC function, to the Company's historical test year expense levels as a means to forecast these costs for Pacific Power during the rate year, through March 31, 2016.[80]

56 Staff, Boise White Paper, and Public Counsel all oppose the Company's proposal. They argue that it is too far a departure from historical test year principles, including most significantly that *pro forma* adjustments to test period costs must be known and measureable.

57 Staff argues that because there is no direct connection between the IHS Global Insight indices and Pacific Power's operations in Washington, the Company's proposed adjustment simply fails to reflect any specific known and measurable cost the Company incurs in serving Washington ratepayers.[81] "PacifiCorp's proposal fails to meet any reasonable interpretation of the known and measurable standard."[82]

General rate Increase, Wyoming PSC Docket No. 20000-446-ER-14, Order ¶¶ 45, 174 (Dec. 30, 2014)).

[77] Pacific Power Initial Brief ¶134 (citing Dalley, Exh. No. RBD-1T 9:8-13, 10:20-22; Dalley, Exh. No. RBD-3T 7:11-23, 11:19-21). IHS Global Insight is a national economic forecasting consulting company that is widely used to develop economic forecasts. For the utility industry, IHS Global Insight provides industry-specific escalation indices, developed at the Federal Energy Regulatory Commission account functional level. A description of the model used by IHS Global Insight to develop its O&M and A&G indices is attached to Mr. Dalley's rebuttal testimony as Confidential Exh. No. RBD-5C.

[78] *Id.* (citing Siores, Exh. No. NCS-1T 19:5-9).

[79] *Id.* (citing *Id.* at 19:9-11).

[80] *Id.* (citing Dalley, Exh. No. RBD-1T 10:22-23).

[81] Staff Initial Brief ¶ 140.

[82] *Id.*

58 Public Counsel argues that

> Rates in Washington are based on actual historical test year costs and pro-forma known and measurable adjustments, not on estimates and projections. Absent the adoption of a future test year in Washington, with necessary protections and parameters, use of escalation factors in this manner is not reasonable. [83]

It notes that Pacific Power has neither performed any analysis or study, nor commissioned any third party analysis or study, to demonstrate that the O&M and A&G expenses for Pacific Power have historically been increasing at similar rates to the IHS Global Insight factors.[84] The Company submitted no such supportive analysis for the record in this case.

59 Faced with this strong opposition, the Company's principal argument in rebuttal is that its claims of historical under-recovery of costs in Washington should persuade the Commission to largely ignore longstanding regulatory principles and allow "discrete" adjustments that would increase the Company's revenue requirement (*i.e.,* expense recovery) without giving any consideration to possible offsetting revenue during the post-test year period.[85] The Company rationalizes this in its Initial Brief with the argument that "[t]he Company's load forecast shows only 0.2 percent load growth expected between the test year and the rate year, so any changes in the Company's revenues will be substantially less than the changes in costs."[86]

60 *Commission Determination:* The Company's proposed adjustments using the IHS Global Insight indices do not present known and measurable *pro forma* adjustments. The Company supports the use of the IHS Global Insight indices as addressing under-earnings that it claims result from Washington's use of a historic test year. Essentially, this is another effort by Pacific Power to force the square peg of a future test year approach to ratemaking into the round hole of our hybrid test year approach.

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[83] Public Counsel Initial Brief ¶69 (citing *PSE 2009 GRC*, Order 11, ¶ 26).

[84] Public Counsel Initial Brief ¶ 68 (citing Dalley, TR. 383:21-385:14).

[85] Dalley, Exh. No. RBD-3T, at 12:9-17.

[86] Pacific Power Initial Brief ¶ 137 (citing Duvall, Exh. No. GND-1CT 16 Table 3).

61 As Staff points out, under this state's approach to ratemaking the Company should perform an attrition study to show that Company specific trends in non-labor and non-power O&M and A&G expense exceed revenue growth and efficiency gains.[87] Pacific Power, however, has performed no such study either in this proceeding or in any of its previous general rate cases. Indeed, there is no evidence in this record that Pacific Power has under recovered these expenses in Washington.

62 Further, the Company does not demonstrate that its historical growth rate in these expense categories corresponds in any way to the HIS Global Insight indices escalation rate. Finally, the IHS Global Insight indices are based on historical inflation rates, not on forward looking estimates of inflation, which would need to be considered.

63 We therefore reject Pacific Power's proposal to use the IHS Global Insight indices to adjust these operating expenses. Even were we to adopt a future test year approach in Washington, we are not convinced the use of the IHS Global Insight indices would be appropriate because they are neither specific to Pacific Power, nor have they been tested against the Company's actual experience.[88]

C. Net Power Costs – *Pro Forma* (Adjustment 5.1.1)

64 Pacific Power requests *pro forma* Net Power Costs (NPC) in the WCA of approximately $592.7 million, or $135.6 million on a Washington-allocated basis, for the 12 months ending March 31, 2016.[89] This includes approximately $10 million in costs the Company incurs from out-of-state Qualifying Facility (QF)[90] Purchase

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[87] *See* Ball, Exh. No. JLB-1T at 16:11-7:3.

[88] We note that Wyoming, a future test period state, has rejecting the use of these indices by Rocky Mountain Power, PacifiCorp's operating division serving that state. *Re Application of Rocky Mountain Power for Approval of a General rate Increase*, Wyoming PSC Docket No. 20000-446-ER-14, Order ¶¶ 172-173 (Dec. 30, 2014).

[89] Pacific Power Initial Brief ¶¶ 61-86.

[90] QFs were created by Congress in the Public Utilities Regulatory Policy Act (PURPA). Pub.L. 95–617, 92 Stat. 3117 (enacted November 9, 1978). PURPA was part of the National Energy Act of 1978. PURPA established this new class of generating facilities that receive special rate and regulatory treatment and requires regulated electric utilities such as PacifiCorp to buy power from them, if their cost is less than the utility's own "avoided cost" rate determined by each state public utility commission.

Power Agreements (PPAs). Under the Commission's 2007 order approving the WCA inter-jurisdictional cost allocation methodology, Pacific Power must allocate QF costs based on "situs," allocating the costs of these facilities to the states in which they are located.[91] Staff, Public Counsel, and Boise White Paper ask the Commission to follow the WCA in this case and disallow these out-of-state QF costs, reducing accordingly Washington NPC.[92]

65 Boise White Paper recommends additional NPC adjustments by imputing benefits related to the Company's participation in the Energy Imbalance Market (EIM) with the California Independent System Operator Corporation.[93] In addition, Boise White Paper asks the Commission:

- To accept its proposed reduction to NPC related to Network Integration and Transmission (NT) Service from the Bonneville Power Administration (BPA) rather than the smaller amount recommended by Pacific Power.[94]

- To remove duplicative charges Boise White Paper contends result from the Company double-counting of inter-hour wind and load integration costs through two separate NPC charge items.[95]

- To exclude the 2013 Chehalis outage from GRID model outage rate calculations because the outage: 1) is not representative of normal plant operations in the rate period; and 2) resulted from imprudent operation.[96]

1. Qualifying Facilities Contract Costs

66 The Commission addressed at length in its Final Order in Pacific Power's 2012/2013 GRC the Company's proposals in that case to change the way PacifiCorp's inter-

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[91] *WUTC v. PacifiCorp*, Dockets UE-061546 and UE-060817 (consolidated), Order 08, ¶¶ 56-57 (June 21, 2007).

[92] Staff Initial Brief ¶¶ 25-70; Public Counsel Initial Brief ¶¶ 39-40; Boise White Paper Initial Brief ¶¶ 65-75.

[93] Boise White Paper Initial Brief ¶¶ 76-83.

[94] *Id.* ¶ 84.

[95] *Id.* ¶¶ 85-87.

[96] *Id.* ¶¶ 88-90.

jurisdictional costs are allocated to Washington using the WCA inter-jurisdictional cost-allocation methodology.[97] The most significant change the Company proposed would have added more than $10 million to Washington rates by changing the West Control Area method of allocating QF power costs the Company incurs in Washington, Oregon, and California.[98] The Commission rejected Pacific Power's proposal and discussed at length the evidence, the parties' arguments, and the bases for its determination.[99] The Commission also discussed what would be required to support any future proposal to change the WCA methodology.[100]

67 In this case, Pacific Power again requests authority to abandon the WCA situs allocation methodology for PURPA QF power costs. Although it presents three alternative means to change the methodology for allocating these costs, the primary proposal is identical to what it proposed in Docket UE-130043 and the fundamental argument remains the same: that is, the WCA allocation methodology that does not allow Pacific Power to allocate the costs of Oregon and California QFs to Washington should be abandoned in favor of a methodology that effectively allows the allocation of such costs to Washington.

68 *Commission Determination:* In Pacific Power's 2012/2013 GRC the parties presented extensive testimony and argument concerning the QF cost allocation issue. The Commission discussed the issue at length in Order 05, its Final Order in the case entered on December 4, 2013.[101]

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[97] *WUTC v. PacifiCorp*, Docket UE-130043, Order 05 ¶¶ 74-94 (December 4, 2014).

[98] PacifiCorp's costs are allocated among five of the six states in which it does business as either Pacific Power (Oregon, Washington, and California) or Rocky Mountain Power (Idaho, Utah and Wyoming) using the so-called Revised Protocol. The Commission rejected the use of this allocation methodology in 2006. *WUTC v. PacifiCorp,* Docket UE-050684, Order 04 ¶ 64 (April 17, 2006). In the Company's next general rate case the Commission approved PacifiCorp's proposed WCA cost-allocation methodology for Washington. *WUTC v. PacifiCorp*, Dockets UE-061546 and UE-060817 (consolidated), Order 08, ¶¶ 49-52 (June 21, 2007). Pacific Power used the approved WCA method in its 2008, 2009, 2010 and 2011 general rate cases in Dockets UE-080220, UE-090205, UE-100749, and UE-111190, respectively. The Commission extended the WCA trial period in the 2011 proceeding, as the parties requested and, following an unsuccessful collaborative process among interested stakeholders, Pacific Power again used the WCA, albeit unilaterally proposing to make several changes, including changing the allocation method for QF costs using the Revised Protocol approach.

[99] Docket UE-130043, Order 05 ¶¶ 95-114.

[100] *Id.* ¶¶ 92-94.

[101] *Id.* ¶¶ 74-94.

69 Pacific Power, bypassing its opportunity to seek reconsideration under RCW 34.05.470, appealed the Commission's order to the Washington Court of Appeals, Division II, on January 2, 2014. The Company makes essentially the same arguments to the Court concerning the allocation of QF costs that the Commission expressly rejected in Order 05. The Commission answers these arguments in its brief to the Court, filed on December 24, 2014. As of the date of this Order, that case is still pending in the Court of Appeals.

70 Pacific Power filed this rate case on May 1, 2014, making the same QF cost allocation proposal. Again in this case, the parties present extensive testimony and argument, much of which repeats in one form or another what the Commission heard in the prior case and summarizes what the Commission said in Order 05, entered just five months before Pacific Power filed this case. We decline to discuss, nor will we discuss this matter at length again so recently on the heels of Order 05, especially given that the matter is still pending judicial review.

71 Pacific Power seeks to re-litigate the Commission's decision in UE-130043 to depart from the WCA inter-jurisdictional cost allocation methodology and, by one means or another, include the costs of Oregon and California QFs in Washington rates. At the same time, Pacific Power is pursuing the identical issue, making the same arguments, in the Court of Appeals. The Commission is not obligated to decide this issue again in this proceeding and exercises its statutory authority to decline to do so.

72 RCW 80.04.200 states, in pertinent part:

> Any public service company affected by any order of the commission, and deeming itself aggrieved, may, after the expiration of two years from the date of such order taking effect, petition the commission for a rehearing upon the matters involved in such order, setting forth in such petition the grounds and reasons for such rehearing, which grounds and reasons may comprise and consist of changed conditions … , or that the effect of such order has been such as was not contemplated by the commission or the petitioner, or for any good and sufficient cause which for any reason was not considered and determined in such former hearing.

This statute establishes a two-year period during which an issue decided by the Commission need not be reheard. The meaning of this statute was tested in 1997.[102] The Washington Supreme Court held:

> The same issues which were considered in the depreciation case are the issues the Company sought to introduce in the rate case. Therefore, under RCW 80.04.200, the Commission did not have to rehear those issues in the rate case only months after they had been considered in the depreciation case. Under this statute, whether or not US West had "new" evidence or wished to argue that conditions had changed with regard to competition, the Commission was not obligated to hear the issues again within the two-year period.[103]

73 Pacific Power's QF proposal in this case falls squarely within the language of RCW 80.04.200, as discussed by the Supreme Court in *US West*. The Commission decided the QF issues in the Company's 2013 rate case, which was decided only five months before the Company filed this case seeking in one fashion or another the same result previously rejected. This is well within the two-year window set forth in the statute and the Commission is under no obligation to rehear the matter. Further, Pacific Power put this matter before the Court of Appeals and we should not, for reasons of

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[102] *US West Communications, Inc. v WUTC,* 134 Wn.2d 74 (1997). The Supreme Court's Opinion relates that:

> In May 1994, US West filed its petition in the depreciation case seeking adjustments of its depreciation rates and accounting methodology. . . . In February 1995, US West filed this rate case. In May 1995, the Commission filed its decision in the depreciation case. . . . In January 1996, after motion, responses and argument, the Commission issued its Eleventh Supplemental Order in the rate case excluding the depreciation evidence from being heard again in the rate case. . . . US West appealed the rate case to the Superior Court, arguing that the Commission artificially separated the evidence in the depreciation case from the evidence in the rate case. The Superior Court held that it was not incumbent on the Commission to revisit the same issues in the rate case that had just been considered in the depreciation case.

134 Wn. 2d at 103-04. US West argued to the Supreme Court that the Commission "was required to consider the depreciation evidence again in the rate case" and "it had new and updated evidence to present on the depreciation issues not available in the depreciation case." *Id.* at 104.

[103] *Id.* at 105. The Court acknowledged that it is within the Commission's discretion under RCW 80.04.200 to rehear issues within the two year stay-out period, and that "[d]iscretionary decisions of the Commission are only set aside on a clear showing of abuse." *Id.*

comity, take up again the same issues that are pending there. The effect of our determination to not rehear this question is to reject for purposes of this case Pacific Power's untimely proposal that we abandon the WCA inter-jurisdictional cost allocation methodology for QF facilities.

2. Jim Bridger Coal Costs

74 Mr. Duvall testifies that *pro forma* coal fuel expense increased by $2.3 million on a Washington-allocated basis, from $48.3 million in the Company's 2013 GRC to $50.6 million in this case.[104] This net increase reflects an approximate $0.4 million decrease in volumes and a $2.7 million increase in costs due to higher prices for coal from the Bridger Coal Company (BCC) and the Black Butte mine, which furnish fuel to Jim Bridger, and the Rosebud mine, which furnishes fuel to Colstrip. The current Black Butte coal supply agreement was through 2014, with an extension into 2015 to allow for delivery of previously deferred contract tonnage. The previously deferred contract tonnage was projected to be delivered in the first quarter of 2015 and the Company assumed unchanged pricing terms for the first quarter of 2015.[105] Pacific Power projected increases for the balance of 2015 for Black Butte and BCC for the full 12 months after the end of the test period. The Company includes *pro forma* period costs for coal at the Colstrip facility based on Western Energy's 2014 Annual Operating Plan (AOP) for the Rosebud mine, which was published in fall 2013.[106]

75 The Company's rebuttal testimony includes an update that increases NPC by just under 11 percent relative to the as-filed NPC: $5.4 million on a Washington-allocated basis. This increase is largely attributable to changes in coal prices and increased volumes at the Jim Bridger coal plant in Wyoming.[107]

76 Ms. Crane testifies the price of Black Butte coal reflected in her rebuttal NPC is the result of a higher delivered price obtained in response to a request for proposals for Wyoming coal by the Bridger plant owners in June 2014.[108] The increase in BCC

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[104] Duvall, Exh. No. GND-1CT at 18:2-7.

[105] *Id.* at 19:17-20:4.

[106] *Id.* at 18:14-17.

[107] Crane, Exh. No. CAC-1CT 2:13-15; 3:6-12.

[108] *Id.* at 4:12-19.

prices reflects the Company's updated mine plan, which was prepared in July 2014 and finalized in November 2014.[109]

77 The Company's rebuttal NPC costs also include updated coal prices for the Colstrip plant as a result of an updated operating plan for the Rosebud mine.[110] Ms. Crane testifies that the Company's direct case reflected mining costs based on the mine operator's 2014 AOP. In October 2014, the mine operator provided the Colstrip owners with the final 2015 AOP increasing WCA NPC by a small amount.[111]

78 Although the parties elected not to contest these adjustments at the close of the case, Boise White Paper expressed by means of a motion to strike testimony its dissatisfaction with having significant price increases brought to the parties' and the Commission's attention only in the Company's rebuttal testimony. The Commission denied the motion because it does not appear the Company intentionally set out to prejudice the other parties with respect to the coal price update. Indeed, the Company stated that it had no objection to the parties having an opportunity to file supplemental testimony on the issue. In Order 07, denying Boise White Paper's motion, the Commission invited parties to seek leave to file supplemental testimony if they wished, and stated it "would be receptive to accommodating any such request" and, if asked, would "establish appropriate additional process on a reasonable schedule."

79 We mention these facts because the Commission is concerned when a company presents significant changes to its case at the time of its rebuttal filing. This can be unsettling to the parties and potentially can disrupt a carefully planned procedural schedule close in time to a planned evidentiary hearing. Thus, we do not wish to leave unremarked the event of Pacific Power's late notice of significant price increases in coal fuel costs in this case. We caution that the Commission may not be receptive in a future case to allowing such testimony, if challenged, and may be particularly disinclined to do so on any issue other than one affecting net power costs. The Commission generally is more lenient with respect to power cost updates because these most often result from changes in the fuel markets that are readily verifiable from various public sources. Pacific Power's coal cost update is a bit of a closer call,

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[109] *Id.* at 5:18-20; *see also* Declaration of Cindy A. Crane in Support of Pacific Power's Response in Opposition to Motion to Strike [Ms. Crane's rebuttal] Testimony at ¶¶ 5-6.

[110] *Id.* at 11:6-13.

[111] The exact amount is confidential as shown in Crane, Exh. No. CAC-1CT at 11:11-13.

based as it is on the results of a request for proposals (RFP) issued in June 2014, the results of a process that we had no opportunity to evaluate for prudence.

80 In any event, we take this opportunity to caution that in our proceedings the purpose of the rebuttal round of testimony is to provide a party seeking a rate increase an opportunity to rebut evidence presented by other parties in their response testimonies. Any evidence presented on rebuttal that is outside this purpose may be rejected. In the final analysis, however, we accept these adjustments to NPC as a result of the changes in coal prices at Jim Bridger, and the minor modification at the Colstrip facility, as being appropriate and meeting the known and measurable test. These adjustments to the NPC for higher contractual coal costs will result in a $25 million increase on a total WCA basis and $5.7 million on a Washington-allocated basis.

3. Energy Imbalance Market Costs

81 PacifiCorp and the California Independent System Operator (CAISO), as sole participants, launched the Western Energy Imbalance Market (EIM) on November 1, 2014. The EIM is a voluntary, sub-hourly market administered by CAISO serving the PacifiCorp West, PacifiCorp East, and CAISO Balance Authority Areas (BAA). It is expected to provide efficient dispatch of imbalance energy across the BAAs every five minutes.[112]

82 The Company does not reflect the imbalance market's impact on its rate base, rate year revenue, or expenses. Mr. Duvall testifies that the costs and benefits of the EIM are not sufficiently known and measurable at this time. He observes that the EIM is new and states that "key EIM components are still being developed and implemented."[113] In addition, he points out that the expected imbalance costs and benefits may vary depending on transfer capability available, making costs and benefits difficult to forecast.[114]

83 Mr. Mullins, for Boise White Paper, testifies that "if the Commission determines other major pro-forma capital additions should be included in revenue requirement—such as the Merwin Fish Collector—then EIM costs and associated benefits should

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[112] Mullins, Exh. No. BGM-5CT, at 2.1.1.

[113] Duvall, Exh. No. GND-1CT, at 7:4-9.

[114] *Id.* at 7:12-15.

also be reflected in revenue requirement."[115] Mr. Mullins testifies that the Company proposes to include in rates a number of post-test period capital projects with smaller capital budgets and later in-service dates than the EIM expenditures. Yet, he says, Pacific Power has not proposed that any costs or benefits of the EIM be reflected in rates. In Mr. Mullins' view, the Commission should not apply "a double standard for determining which pro-forma capital and operating costs to include in revenue requirement."[116]

84 To support his proposal Mr. Mullins relies on a March 2013 study prepared by Energy and Environmental Economics, Inc. (E3), titled "*PacifiCorp-ISO Energy Imbalance Market Benefits*" which examines both the feasibility and benefits of developing an EIM between PacifiCorp and the CAISO.[117] Mr. Mullins argues that if the Company relied on the E3 report in its decision to participate in the EIM, then the same report should be sufficient enough to establish EIM benefits for ratemaking purposes.[118] Relying solely on the report, Mr. Mullins provides discussion on the costs and benefits of the Company's participation in the new EIM program. He begins by recognizing an estimated initial investment and operating costs of the Company by increasing expenses by $237,000 in O&M expenses and increasing the test year's rate base of $1.2 million. The adjustments result in a $394,087 increase in Pacific Power's Washington allocated revenue requirement.[119]

85 The Company responds to Boise White Paper's proposal by pointing out that it is currently impossible to project accurately the amount of offsetting benefits in the rate period.[120] Mr. Duvall testifies that because of Washington's known and measurable standard, and its adherence to the matching principle, the Company decided not to include EIM costs and benefits in this filing.[121] Mr. Duvall testifies that EIM benefits are "unlike other forecast items in this case because there is no actual or analogous

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[115] Mullins, Exh. No. BGM-1CT at 19:2-6.

[116] *Id.* at 19:16-23.

[117] Mullins, Exh. No. BGM-5CT.

[118] Mullins, Exh. No. BGM-1CT at 31:5-9.

[119] *Id.* at 21:3-7.

[120] Duvall, Exh. No. GND-4CT at 30:21-23.

[121] *Id.* at 30:23-31:3.

historical data on which to base an economic forecast for ratemaking purposes."[122] In addition, the EIM is new and untested. He expects that a reasonable ramp-up period will be required before EIM benefits are fully realized and measurable.[123]

86 Mr. Duvall's "overarching criticism" of Boise White Paper's reliance on the results of the E3 Report is that there is no nexus between the study and "the specific *pro forma* period in this case or the WCA methodology."[124] In addition, according to Mr. Duvall, Boise White Paper's proposed adjustments include benefits that are already reflected to some extent in the Company's existing forecast and reflect a reduction in imbalance costs that are not included in the Company's power cost model forecast or customers' rates to begin with.[125]

87 Mr. Duvall discusses, too, that "the Company used the E3 Report to verify that the EIM would be cost effective, not as a study to quantify its near-term benefits for ratemaking."[126] He explains that the report is based on a forecast of the Western Electricity Coordinating Council's 14-state region for 2017, with corresponding loads and market prices, with the benefits adjusted to 2012 dollars. Thus, the benefits determined by the E3 Report depend on the costs of system operation in 2017 and do not reflect costs included in the Company's forecasted NPC in this case. Mr. Duvall states that "[d]ifferences include essential assumptions no party would accept for use in GRID in this rate case including different test period, forward price curves, transmission topology, and differences in the underlying production dispatch model and associated model architecture."[127]

88 Mr. Duvall, having stated the Company's general objections to Boise White Paper's proposal, also testifies in considerable detail concerning Pacific Power's specific objections to imputing benefits for EIM Inter-Regional Dispatch, EIM Intra-Regional Dispatch, EIM Reserve Diversity, and Within-Hour Dispatch. Such evidence may prove useful in a future case, but we find no need to discuss it here where the issue

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[122] *Id.* at 31:18-23.

[123] *Id.*

[124] *Id.* at 33:18-34:6.

[125] *Id.* The Company's proprietary power cost model is identified as GRID, the acronym for Generation Regulation Initiative Decision.

[126] *Id.* at 34:9-10.

[127] *Id.* at 34:14-18.

can be determined at the threshold and requires no nuanced analyses of specific issues beyond the threshold.

89 *Commission Determination:* While we find Boise White Paper's arguments insightful, we find that Mr. Mullins' estimates of costs and benefits are too uncertain to support the sort of adjustments he proposes on behalf of his client. As the EIM is still in its infancy from an operational standpoint, it makes more sense to consider the costs and benefits of this new intra-hour balancing tool in a future general rate case when the Company has more actual data and operational experience that corresponds to a test year. Contrary to what Mr. Mullins testifies, the E3 report, a planning document forecasting WECC-wide benefits in 2017, is not a proper basis upon which to determine costs that the Commission can consider to be known and measurable for purposes of setting rates in this case. Given that the E3 report is the principal basis upon which Mr. Mullins relies in estimating costs and benefits, we are constrained to reject Boise White Papers recommended adjustments to NPC in this case.

4. Network Integration and Transmission Service Costs

90 The Bonneville Power Administration (BPA) provides Network Integration Transmission Service (NT Service) to Pacific Power, which allows the Company to provide service to several areas in Washington and Oregon that Mr. Mullins refers to as "load pockets." The Company included for recovery in rates the wheeling costs of the NT Service in power costs, calculating these costs using the non-coincident peak for each load pocket.

91 Mr. Mullins testifies for Boise White Paper that the billing factor assumed by the Company for NT Service is different than the actual billing factor in BPA's Open Access Transmission Tariff (OATT),[128] which uses "the customer's Network Load on the hour of the Monthly Transmission System Peak Load, as those terms are defined in BPA's OATT."[129] Mr. Mullins disputes the Company's assumption that the non-coincident peak load equals the coincident peak load and testifies that "the Company's calculation overstates the billing factor and related costs associated with BPA NT Service reflected in NPC."

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[128] Mullins, Exh. No. BGM-1CT at 45:1-9.

[129] *Id.*

92 In rebuttal, Mr. Duvall "accepts in concept Boise's adjustment to reduce wheeling expenses related to BPA NT Service," but he testifies that Boise White Paper's proposed calculations are flawed and overstate the required adjustment.[130] Mr. Duvall characterizes Boise White Paper's proposed adjustment as overly complicated resulting in a forecasted wheeling expense forecast that is less than 2013 actual levels. This result, he suggests, is particularly unreasonable considering a 2013 BPA rate increase.

93 The Company proposes "a straightforward and reasonable" alternative adjustment to reduce NT Service wheeling expense. Mr. Duvall proposes to calculate the NT Service expense based on the historical 2013 expenses, adjusted to account for the October 2013 rate increase.[131] This adjustment results in a reduction to WCA NPC of $0.8 million.

94 *Commission Determination:* The Company's approach is at least straightforward and we consider it reasonable for purposes of this case.[132] The record demonstrates, however, that it may be possible to calculate these costs with greater accuracy based on BPA's OATT and actual experience during the test year. We expect to see these costs supported by a more refined approach in the Company's next case.

5. Inter-Hour Wind and Load Integration Costs

95 The Company proposes in its direct case to refine it's forecasting of NPC in the GRID model by utilizing actual 2012 wind energy output data from the Company's owned and purchased wind facilities shaping hourly wind generation profiles.[133] According to Mr. Duvall, this refinement improves the accuracy of its NPC forecast by using recent wind data to develop profiles which better capture the hourly volatility of wind generation. Mr. Duvall provides a detailed technical discussion in his testimony and states that the Company has tested this refinement using method developed in a

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[130] Duvall, Exh. No. GND-4T at 65:2-7.

[131] *Id.* at 66:1-8.

[132] *Id.* at 65:9-15.

[133] *See generally* Duvall, Exh. No. GND-1CT at 26:3-29:9.

technical report published by the National Renewable Energy Laboratory (NREL).[134] Mr. Duval testifies that:

> In its study, NREL calculated the coefficient of variation (COV), defined as the ratio of standard deviation value to plant nameplate capacity, to gauge the short-term variability of wind generation. The Company applied this same calculation on four of its wind resources located in the west control area.[135]

Mr. Duvall says the results show that the COV of the Pacific Power wind plants is fairly consistent over time and that the variability in the Company's revised modeling is much closer to the historical levels.[136]

96 Boise witness Mr. Mullins testifies that by including the newly proposed hourly wind shaping methodology, a similar integration costs *pro forma* adjustment by the Company outside of the GRID model should be removed.[137] He claims that with the change in the GRID model proposed by the Company, these inter-hour wind and load integration costs are now being double-counted within the model and the *pro forma* charge outside the model.

97 Mr. Duvall maintains in his rebuttal testimony that inter-hour integration of load and wind resources is appropriately reflected in the Company's NPC and is not duplicated by modeling load and wind profiles on an hourly basis. He testifies that Mr. Mullins basic assumption that system-balancing wind integration costs and system costs associated with the hour-to-hour variability in wind output are the same is flawed. The increase in NPC due to wind variability is not the same as inter-hour integration cost and both must be recognized.[138] Mr. Duvall says that wind variability is addressed within the GRID model using the proposed wind shaping data. The Company uses the results of the model to commit generation resources based on the model's forecasted load and wind generation. Wind inter-hour integration costs, on

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[134] Y. H. Wan, *Long-Term Wind Power Variability*. Technical Report, NREL/TP-5500-53637 (Jan. 2012). Available online at http://www.nrel.gov/docs/fy12osti/53637.pdf.

[135] Duvall, Exh. No. GND-1CT at 28:16-29:2.

[136] *Id.* at 29:3-29:9.

[137] Mullins, Exh. No. BGM-1CTr at 46:18-47:9.

[138] *See generally* Duvall, Exh. No. GND-4T at 48:18-51:15.

the other hand, reflect charges associated the costs of balancing around the actual wind output and load. According to Mr. Duvall, it is appropriate to reflect both in the Company's cost of service.

98 Boise White Paper also argues that the wind inter-hour integration costs is a new charge that has neither been included in prior filings nor documented as a modeling change in this filing.[139] Mr. Duvall responds to this by pointing out that the charge was reflected in the prior 2010 Wind Integration Study, which reflected the combined load and wind integration costs.[140] The 2010 Wind Integration Study was used in Docket UE-111190 reflecting in rates the costs for inter-hour integration costs for load.[141] In the new 2012 study, responding to stakeholders, the costs were broken into Wind and Load related costs.

99 *Commission Determination:* We decline to accept Boise White Paper's proposed inter-hour wind and load integration adjustment. The Company describes in detail its system of modeling and its two-step process from forecast to actual, thereby explaining what it portrays as a misconception by Mr. Mullins. Pacific Power demonstrates convincingly that it has not double-counted costs or otherwise reflected the same wind integration adjustment using two different approaches. We reject Boise White Paper's recommendation that we require removal of the Company's outside-of-GRID *pro forma* adjustment of wind integration costs.

6. Chehalis Outage

100 In November 2013, one of the three generation units at Chehalis experienced an outage caused by the failure of a step-up transformer. Boise White Paper recommends that the Commission exclude the 2013 Chehalis outage from GRID model outage rate calculations because the outage: 1) is not representative of normal plant operations in the rate period; and 2) resulted from imprudent operation.[142]

101 Pacific Power points out that in the Company's 2010 rate case, Boise White Paper's NPC witness through its trade group, the Industrial Customers of Northwest Utilities

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[139] Mullins, Exh. No. BGM-1CTr at 49:6-16.

[140] Duvall, Exh. No. GND-4T at 51:4-15.

[141] *Id.*

[142] Mullins, Exh. No. BGM-1CTr at 50:13-15.

(ICNU), testified that an outage should be excluded as anomalous only if it exceeds 28 days.[143] Since the Chehalis outage was less than 28 days, Pacific Power reasons it is within the realm of "normal."[144] What the Commission determined in Pacific Power's 2010 GRC, however, is that

> The dispute before us is how to set an annual outage rate in light of a single, large, anomalous event. We agree with Staff that the purpose of establishing an annual outage rate is to represent expected outage levels during the rate year. PacifiCorp does not dispute that the approximately seven month outage is an anomaly. *ICNU's proposal to remove all outages longer than 28 days addresses the issue, but lacks substantial justification.*[145]

The Commission's rejection of a proposed standard should not be cited as basis for drawing the inference Pacific Power urges us to make. Moreover, Boise White Paper says it recommends the exclusion of the 2013 Chehalis outage not on the basis of its duration, but because it was the third catastrophic outage within a decade, all due to the same transformer bushing design failure.[146]

102 Boise White Paper's principal argument, in any event, is that the outage was the result of imprudence because the plant had experienced similar types of outages in prior years, one in 2006 and one in 2011.[147] Mr. Mullins includes in his largely confidential testimony on this issue a discussion of the root cause analysis from which he infers imprudence. Mr. Ralston, who has 28 years of experience in plant operations and maintenance and is responsible for the operation and maintenance of the PacifiCorp generation fleet, testified on rebuttal that the plant was operated consistent with standard industry practices, that the Company's actions following the 2011 outage were reasonable, and that the two prior outages would not have caused

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[143] Pacific Power Initial Brief ¶ 114 (citing *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 139 (Mar. 25, 2011)).

[144] Mullins, Exh. No. BGM-1CT 50:11-13.

[145] *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 141 (March 25, 2011) (emphasis added).

[146] Boise White Paper Reply Brief ¶ 55.

[147] Pacific Power did not own the Chehalis plant in 2006.

the Company to operate the plant differently.[148] In fact, following the 2011 outage, the Company installed monitoring equipment on the generator step-up transformers specifically to allow the Company to assess the risk of future failures—an action that exceeds standard industry practice.[149]

103 Pacific Power, again relying on Mr. Ralston's testimony, also disputes Boise White Paper's claims that in the month leading up to the 2013 failure, the monitoring equipment indicated a problem and that it was "very clear" that the Company was "operating [the plant] in alarm status for a very long period of time."[150] The Company says that "[w]henever the data indicated an abnormality, the Company took immediate action to determine whether remedial steps were necessary, including the removal of the unit from service."[151] Mr. Ralston testifies in this connection that:

> Whenever the data indicated that abnormal conditions were present, it was immediately reported to Chehalis plant personnel from the bushing monitoring equipment. When the Company received abnormal condition notices, the Company contacted the OEM to determine if the abnormal condition warranted action by the Company, such as removal of the transformer from service. In one instance, the Company discovered that the OEM had incorrectly commissioned the equipment. This issue was corrected before the 2013 failure.[152]

104 *Commission Determination:* The focus of Mr. Mullins' testimony for Boise White Paper on this issue is not the duration of the Chehalis outage, but rather on his belief that the repeated and "catastrophic" nature of the event marks it as abnormal. The weight of the evidence concerning imprudence on the part of plant operators favors the Company's argument that it was not such operation on the part of Pacific Power that led to this outage. On balance, we are not persuaded by Boise White Paper's argument and will not require the Company to remove this outage from GRID model outage rate calculations used in determining NPC in this case.

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[148] Pacific Power Initial Brief ¶ 116 (citing Ralston, Exh. No. DMR-2T at 4:20-5:5, 6:5-16, 6:21-7:22, 8:1-10).

[149] *Id.* (citing Ralston, Exh. No. DMR-2T at 4:18-5:5, 6:11-12).

[150] *Id.* ¶ 117 (quoting Mullins, TR. 750:2-751:4).

[151] *Id.*

[152] Ralston, Exh. No. DMR-2T at 5:6-21.

D. PCAM

105 Pacific Power sought approval of a PCAM in its 2006/2007 GRC, arguing that implementation of such a mechanism was justified by the facts that the Company faced volatility in net power costs and because Avista and PSE have power cost adjustment mechanisms.[153] The Commission found that:

> PacifiCorp's circumstances include significant exposure to variability in power costs and this variability is sufficient to justify a PCAM. However, PacifiCorp has designed its mechanism on the basis of the PCAM we approved for Avista, the so-called ERM, without making refinements that our record shows are appropriate in light of PacifiCorp's unique circumstances. Specifically, we find that the design features proposed by the Company and modified by Staff do not appropriately balance risk and benefits. There are two principal reasons:
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> - The accounting for actual and computer-generated-actual costs has not been shown to be reliable.
> - The design of the dead band and sharing bands should reflect the asymmetry of power cost risk that is evident in PacifiCorp's case.[154]

The Commission expressed its receptiveness to a properly designed PCAM for Pacific Power and expressly invited the Company to file a petition within 12 months after Order 08, outside of a general rate case, "seeking approval of a PCAM

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[153] *See WUTC v. PacifiCorp d/b/a Pacific Power and Light Co.,* Docket UE-061546, Order 08 ¶ 59 (June 21, 2007). This was the Company's second request for approval of a PCAM. The first came in Pacific Power's 2005/2006 GRC, Docket UE-050684. The Commission rejected the Company's tariff filing, including the PCAM proposal, based on its reliance on the Revised Protocol method for inter-jurisdictional cost allocation, which the Commission rejected as inappropriate for the determination of rates in Washington. *See WUTC v. PacifiCorp d/b/a Pacific Power and Light Co.,* Docket UE-050684, Order 04 (April 17, 2006). Order 04 includes discussion about the Company's PCAM proposal and offered guidance for a future filing, including the Commission's requirement for appropriate dead bands and sharing bands.

[154] *WUTC v. PacifiCorp d/b/a Pacific Power and Light Co.,* Docket UE-061546, Order 08 ¶ 59 (June 21, 2007)*; see also Id.* ¶¶ 83-87.

consistent with the guidance we provide here and with or without a request for authority to file power cost only rate cases (PCORCs)."[155]

106 Pacific Power did not accept the Commission's invitation to file for authority to implement a PCAM outside of a general rate case. Nor did the Company ask for such authority in its GRC filings in 2008, 2009, 2010, or 2011.

107 Pacific Power filed its third PCAM proposal as part of its 2012 GRC.[156] The Commission rejected the proposal in light of the Company's failure to design it following "the explicit direction the Commission" gave Pacific Power in the earlier cases. The Commission determined that:

> [T]he Company's proposal here is even more at odds with the direction the Commission has given PacifiCorp than its proposals in prior cases that have been rejected. Contrary to express Commission direction, and in contrast to the power cost adjustment mechanisms approved in other PacifiCorp jurisdictions, the Company's proposal here includes neither dead bands nor sharing bands. These are critically important elements that provide an incentive for the Company to manage carefully its power costs and that protect ratepayers in the event of extraordinary power cost excursions that are beyond the Company's ability to control.[157]

The Commission's order in Docket UE-130043 includes a detailed critique of Pacific Power's arguments[158] and concludes:

> What PacifiCorp proposes here does not include any of the specific design elements the Commission has identified in its prior orders. Like

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[155] *Id.* ¶ 60.

[156] *See Utilities & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light*, Docket UE-130043, Order 05 (December 4, 2013). The Company filed its first PCAM proposal in 2005. *See WUTC v. PacifiCorp d/b/a Pacific Power and Light Co.,* Docket UE-050684, Order 04 (April 17, 2006), and its second a year later, in 2006. *See WUTC v. PacifiCorp d/b/a Pacific Power and Light Co.,* Docket UE-061546, Order 08 (June 21, 2007).

[157] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-130043, Order 05 ¶ 170.

[158] *Id.* ¶¶ 171-72.

> Staff, we are open to consider a properly designed PCAM proposal that incorporates the appropriate balance between the Company and ratepayers. Yet, the Company's proposal in this case really is nothing more than a request for a power cost tracker and true-up mechanism that will guarantee the Company full recovery of its power costs on a continuing basis. We are not prepared to embrace such a mechanism and, therefore, reject PacifiCorp's proposed PCAM.[159]

108 The Company elected in this case not to file "a properly designed PCAM proposal that incorporates the appropriate balance between the Company and ratepayers." Instead, Pacific Power filed another tracker mechanism, a so-called Renewable Resource Tracking Mechanism (RRTM), providing a dollar-for-dollar annual true-up between forecast and actual power costs for the Company's renewable resource generation. We discuss below several of the fundamental failings of this proposal that give us independent reasons to reject it. Also important to our decision to reject the RRTM, however, is Commission Staff's interest in effecting a broader solution to address the Company's challenges in terms of power cost recovery.

109 To this end, Mr. Gomez testifies to Staff's belief that "the Commission has provided more than sufficient guidance to Staff and the Company over the last nine-years on this issue to warrant action and to move forward with implementation of a PCAM once and for all."[160] Mr. Gomez, focusing on the Commission's detailed discussion of a PCAM proposed in Pacific Power's 2006 GRC,[161] addresses the key factors that led the Commission to reject Pacific Power's proposal and explains Staff's view of the appropriate means to address these issues in this case.

110 Mr. Gomez first discusses the Commission's concern relative to the Company's proposed use of a computer-generated cost methodology to determine both forecasted normalized base power costs and to determine "actual costs" that would be trued-up on an annual basis. In this regard, the Commission discussed in Order 08 that:

> Base power costs are a statistical estimation of what level of costs is expected under normal conditions. Because this is an estimate, it is not expected to match the actual costs incurred in any given year. The core

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[159] *Id.* ¶ 173.

[160] Gomez, Exh. No. DCG-1CT at 19:13-16.

[161] *WUTC v. PacifiCorp*, Docket UE-061546, Order 08 ¶¶ 59-111 (June 21, 2007).

> idea of a power cost adjustment mechanism is to true-up these estimated costs with actual costs that are the measured and documented costs that did occur in a given year.
>
> Our concern is that the computer-generated, pseudo-actual costs will themselves be only estimates including some statistical (i.e., modeling) variability (i.e., error). The Company and Staff contend that actual data, rather than assumptions, will be used in the computer model. Presumably that will reduce the modeling error and produce a more precise result. Truing-up one estimate with another more precise estimate may be justified, but the risk is that neither will be accurate and using two inaccurate, even if precise, estimates of cost to set cost-based rates could lead us to depart farther and farther from actual costs. A key problem with this approach is that we would never know.[162]

111 Mr. Gomez testifies that in Docket UE-130043, the Company's 2012/2013 GRC, Pacific Power abandoned its prior proposal that relied on computer-generated costs and, instead, offered to report actual NPC per its books and records. In Staff's view, "[t]his approach resolves the first threshold hurdle to a properly designed PCAM for Pacific Power."[163]

112 Turning to the issue of dead bands and sharing bands, Mr. Gomez testifies that Staff's proposal would resolve the second point of concern stated in Order 08 by proposing a PCAM with properly designed sharing and dead bands. In the earlier case, the Commission included in Order 08 at Table 2, reproduced here, showing the parties' respective proposals for dead bands and sharing bands in the 2006/2007 time frame:

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[162] *Id.* ¶¶ 76-77.

[163] Gomez, Exh. No. DCG-1CT at 20:13-14.

PCAM Proposals[164]

	Dead Band	**Sharing Bands**	**Other Features**	**Risk-Adjustment**
PacifiCorp	+/-$3 M	+/- $3- 7.4M 60% customer >$7.4M 90% customer	Include fixed cost for new resources ≤ 50 MW for ≤ 2-year term; Retail Load Adjustment; $3 M threshold for cost-recovery.	None
Staff	+/-$4M	+/- $4 – 10M 50% customer >$10M 90% customer	No fixed cost for new resources (only variable cost); Retail Load Adjustment; $6 M threshold for cost-recovery.	Reduction in equity component of capital structure to 42% [ROR = 7.90]
ICNU	+/-$8.6 M	+/- $8.6 – 17.3M 50% customer > $17.3 85% customer	No other detail	ROE reduction of 30 basis points [ROR = 7.92]

The Commission expressed its concern that none of these proposals reflected the asymmetry in the distribution of net power costs that "skewed [them] toward higher costs, in part because poor hydropower is correlated with higher wholesale power costs and higher fuel costs."[165] Order 08 states that:

> An optimally designed PCAM would recognize the inequality between upside and downside risk in its design of deadbands and sharing bands. For example, to equally balance risk with benefit, the deadband and sharing bands should be set at lower levels on the "lower cost" side of base costs to increase the expected value of customer benefits enough

[164] *WUTC v. PacifiCorp,* Docket UE-061546, Order 08 ¶ 66 (June 21, 2007).

[165] *Id.* ¶ 85.

> to balance the expected value of customer risks on the "high side" of base costs.[166]

113 Staff proposes in this case a dead band of plus or minus $25 million on a WCA basis which corresponds to about 5 percent of the average NPC costs for the Company on a WCA basis. How Staff determines this level on a WCA basis is unclear. It is also not clear why, unlike Staff's recommendation in Pacific Power's 2006/2007 GRC, this is not reduced to a Washington basis that would allow for comparison to earlier proposals.

114 As to the sharing bands Staff proposes in this case:

> [A]ny remaining portion of the variance above or below the dead-band will be shared with customers in different proportions depending if the variance between base and actual NPC reflects a year-end surcharge or rebate. Under-recovery of NPC (that is, in the surcharge direction) will be shared on a 50/50 basis between customers and the Company. To reflect asymmetry of power cost distribution, over-recovery of NPC (that is, in the rebate direction) is shared by 75 percent going to customers and the remainder retained by the Company.[167]

Mr. Gomez illustrates the operation of these proposed bands in a confidential exhibit using "actual NPC results provided by the Company in the last rate case [in Docket UE-130043,] which were updated with results from 2012 and 2013."[168] Again, however, Staff does not explain the bases for its choice of a single sharing band or the degree of asymmetry reflected in the sharing mechanism it proposes.

115 In considering the types of costs that would be included in Staff's proposed PCAM, Mr. Gomez testifies that Staff accepts the approach proposed by Pacific Power in its 2012/2013 GRC. That is, the PCAM is calculated "using all components of NPC as traditionally defined in the Company's general rate cases and modeled by the Company's GRID model."[169] Mr. Gomez provides details in his testimony

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[166] *Id.* ¶ 86.

[167] Gomez, Exh. No. DCG-1CT at 22:16-22.

[168] *Id.* at 20:15-20 (referring to Exh. No. DCG-5C).

[169] *Id.* at 21:3-5.

identifying the specific FERC accounts that are included.[170] Thus, Mr. Gomez testifies, "the proposed PCAM for PacifiCorp will be very similar to Avista Corporation's Energy Recovery Mechanism (ERM),"[171] on which the Company based its own proposal in the 2006/2007 GRC.

116 Also like the Avista ERM, Staff's proposed PCAM will include a monthly retail revenue adjustment applied to the monthly difference between actual NPC and forecasted base NPC. The retail revenue adjustment will reflect the power production expenses recovered through base retail revenues due to changes in retail load, as follows:

> Base NPC will be divided by the base load MWh to arrive at a net power cost sales factor (SF) expressed in dollars per MWh. The monthly retail revenue adjustment used in the PCAM will be computed by multiplying the SF by the difference between actual and base monthly retail MWh sales. If actual MWh sales are greater than base, the retail revenue adjustment will reduce the PCAM deferral. If actual MWh sales are less than base, the retail revenue adjustment will increase the PCAM deferral.[172]

117 Staff proposes a carrying charge on the customers' share of NPC deferral balances using the Company's actual cost of debt. This is to be updated semi-annually and applied to NPC deferral balances less associated accumulated deferred income taxes. Staff would require the Company to report semi-annually the result of the updates to the parties in this proceeding. Interest would be accrued monthly and compounded semi-annually.[173]

118 The deferrals will trigger a rate adjustment when the customers' share of Washington-allocated NPC deferrals accumulates to 10 percent of base retail revenues. If this happens, Pacific Power will file to implement a surcharge or rebate through a separate tariff schedule dedicated to this purpose. The proposed effective date of the tariff must allow for a 90-day review and approval process. The Company may propose a

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[170] *Id.* at 21:5-16.

[171] *Id.* at 21:17-19.

[172] *Id.* at 22:1-10.

[173] *Id.* at 23:5-10.

different effective date, subject to Commission approval, to minimize the number of rate changes to customers.[174]

119 Any surcharge or rebate will be spread to rate schedules on the same basis as power costs are allocated using base revenues approved in this proceeding, unless otherwise changed in a future rate proceeding. Within each rate schedule the rate adjustment will apply to the energy charges on a uniform cents per kilowatt-hour basis using the most recent normalized kilowatt-hours as filed annually by the Company pursuant to Commission Basis Reporting requirements. There is an exception for street and area light rates, which will be adjusted by a uniform percentage. The rate adjustment will be in effect for a 12-month period and only one surcharge or rebate will be in place at any given time.[175]

120 Finally, Staff proposes that the Company be required to file quarterly reports of activity in the PCAM when it files its quarterly report of actual operations. In addition, the Company will file annually, on or before April 1st of each year, its PCAM deferrals from the previous calendar year. Standard discovery rules will apply for Company responses to data requests allowing the Commission Staff and interested parties the opportunity to review the deferral information during a 90-day review period ending June 30th of each year. The 90-day review period may be extended by agreement of the parties participating in the review, or by Commission order. The Commission will be asked to confirm and approve the deferral balances in an open meeting or to conduct appropriate process if they are challenged.

121 *Commission Determination:* We agree with Pacific Power's repeated assertions over the past 10 years that it should have a power cost adjustment mechanism in place to address higher than normal variability in its net power costs, just as do the other electric power utilities subject to the Commission's jurisdiction, PSE[176] and Avista.[177] However, the Company has yet to come forward with a proposal that includes the properly designed elements the Commission has clearly said it requires. This is no longer acceptable, especially considering the clear, repeated discussion by the Commission in prior orders concerning the minimum requirements for a PCAM.

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[174] *Id.* at 23:13-19.

[175] *Id.* at 23:20-24:5.

[176] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-011570 and UG-011571, Twelfth Supp. Order (June 20, 2002).

[177] *WUTC v. Avista Corporation*, Docket UE-011595, Fifth Supp. Order (June 18, 2002).

Thus, as we discuss in more detail below, we will begin an expedited proceeding within 30 days of entering this Order to develop and implement a full PCAM for Pacific Power consistent with the Commission's direction in prior orders. We expect to complete the proceeding, resulting in a tariff filing by Pacific Power, no later than May 31, 2015.

122 We note that Staff's proposal in this case is well-grounded in precedent, modeled both to be consistent with the ERM the Commission approved for Avista in 2002 and to reflect the guidance the Commission has provided specifically to Pacific Power in earlier cases. Indeed, Staff's effort appears to have been guided to a large degree by Pacific Power's 2006/2007 PCAM proposal, which was based on Avista's ERM, as well as the Commission's discussion of that proposal's failure to reflect circumstances specific to Pacific Power, including issues related to power cost measurement and asymmetry in the distribution of power costs. We commend Staff for proposing such a model.

123 Despite Staff's efforts to craft a well-balanced proposal that conforms to previous guidance from the Commission, we find the record should be developed further with respect to a number of questions including, for example:

- Is it appropriate to use the WCA as the jurisdictional divide for wholesale power costs?
- Is $25 million the appropriate dead band and how did Staff determine this amount?
- Does $25 million reflect normalized variability in power costs?
- How exactly did Staff arrive at its recommendation for a 50/50 sharing between the Company and its customers for under recoveries of NPC that exceed the dead band and a 25/75 sharing for over recoveries, in favor of customers?

124 Given these needs to supplement our record we will conduct further proceedings to identify and resolve the details of designing fully and implementing a PCAM mechanism for Pacific Power. Thus, we will set by separate notice a date for a prehearing conference within 30 days following the entry of this Order to establish a procedural schedule to develop the details we find, and others may suggest, are necessary to implement fully the PCAM we determine is required for Pacific Power. The prehearing conference also will provide a forum for further discussion of what issues require additional development. Finally, the prehearing conference will provide an opportunity to explore the potential for early settlement discussions among the parties, which the Commission strongly encourages.

125 We direct our questions above to Staff, considering that the Company did not file a full PCAM in this case, and that other parties complain of having too little time to contribute meaningfully to the development of such a tool. However, we invite the Company and others who have an interest to bring their own ideas to our attention with detailed explanation and support. We can then tailor a PCAM to the unique characteristics of Pacific Power taking into account a range of well-supported ideas.

126 We believe some additional time is necessary, however, we do not believe that this will require a great deal since these concepts have been discussed in detail for nearly 10 years. We will require Pacific Power to file tariff sheets necessary and adequate to implement a Power Cost Adjustment Mechanism no later than May 31, 2015. If no full-party agreement can be reached by that time, or the Company declines by that date to file a full PCAM consistent with prior Commission orders, we will approve expeditiously a mechanism generally along the lines Staff proposes in this docket.

127 Furthermore, we take this opportunity to reiterate that there is no barrier to the Company filing for approval of a PCORC mechanism, if the Company perceives it to be necessary and appropriate to resolve issues related to the detailed PCAM design.[178]

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[178] *See* Docket UE-061546, Order 08 ¶ 82, which we find worthy of quotation as a means to provide guidance to Pacific Power, and others, with respect to the basis for our thinking vis-à-vis a potential PCORC filing:

> The Company and Staff agree that the variable cost of new resources less than 50 MW and with a term less than 2-years should be included in the PCAM, but disagree on whether fixed costs should be included. The Company argues that including these fixed costs is necessary to accommodate its need to acquire renewable resources in the future to comply with Washington's Renewable Portfolio Standard.[178] PacifiCorp agrees to exclude these fixed costs from the PCAM, however, if the Commission authorizes it to file for approval of PCORC mechanism that accommodates an annual adjustment.[178] In general, we find it appropriate to include in the PCAM the variable costs of smaller, short-term resource additions, but to exclude the fixed costs. There has never been any barrier to the Company filing for approval of a PCORC mechanism. Indeed, it could have done so in this docket, but did not raise the idea until late in the proceeding. Even then, the Company did not make a specific, detailed proposal.

The Company may do so either as part of a settlement agreement in the subsequent phase of this docket, or by means of a separate filing of a unilateral proposal by Pacific Power to which Staff and other interested persons may respond.

E. Renewable Resource Tracking Mechanism (RRTM)

128 As discussed above, Pacific Power proposes in this case a power cost tracker mechanism providing a dollar-for-dollar true-up between forecast and actual power costs on an annual basis that is principally different from its proposal in Docket UE-130043 only because it would track just a part of the Company's power portfolio instead of the full portfolio. Mr. Duvall identifies the mechanism "as a more narrowly tailored mechanism," a Renewable Resource Tracking Mechanism (RRTM) limited to "resources eligible for the renewable portfolio standard (RPS) included in Washington rates."[179] As Mr. Twitchell testifies for Staff:

> While narrower in scope, the RRTM would operate by the same mechanism proposed for the PCAM in 2013. Both proposals would true up projected costs to actual costs and recover any negative differential from ratepayers. If a positive differential exists, then this amount would be returned to ratepayers. The RRTM's reduced scope does not mean that it is not a PCAM; rather, the reduced scope makes it an improperly designed PCAM.[180]

129 The Company's principal argument in support of the RRTM is that it:

> [F]urthers Washington state energy policy and promotes renewable development by mitigating the cost-recovery concerns that arise due to the inherent variability of many renewable resources. By allowing full cost recovery of RPS-eligible resources, the RRTM is consistent with the cost-recovery provision of the EIA, which entitles utilities to

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The Commission will certainly give any such proposal fair consideration if and when filed.

[179] Pacific Power Initial Brief ¶¶ 104-05 (citing Duvall, Exh. No. GND-1CT at 38:5-18).

[180] Twitchell, Exh. No. JBT-1T at 7:3-8.

> 'recover all prudently incurred costs associated with compliance' with the RPS.[181]

Pacific Power argues in addition that because "RPS-eligible resources are largely intermittent" the proposed mechanism "focuses on resources that exhibit significant variability outside the Company's control."[182]

130 Mr. Mullins testifies for Boise White Paper, however, that the annual variability of Pacific Power's RPS resource output has remained relatively stable in recent years, with the relative standard deviation of wind output at only about 6 percent.[183] This is a relatively small to moderate degree of variability and is significantly less variability than experienced by the Company, for example, with its hydropower resources, which have demonstrated a relative standard deviation of 14 percent.[184] Staff argues in this connection, too, that a power cost recovery mechanism including only part of a company's total power costs fails to recognize that "[t]he financial performance of a company's *entire* generation portfolio is what determines whether a company has under- or over-recovered its power costs."[185] Moreover, Pacific Power has a diverse generation fleet, including coal, natural gas, hydropower, and wind resources, all of which exhibit some degree of variability.[186]

131 In point of fact, Pacific Power's generation fleet is, or should be, deployed following principles of economic dispatch. Related to this point, Mr. Twitchell testifies that:

> By segregating wind resources for special cost treatment, the Company ignores the real chance that reduced costs in other areas of its generator portfolio could more than offset any difference between the wind energy costs determined by its NPC model and in-period actuals.[187]

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181 Pacific Power Initial Brief ¶ 105 (internal citations omitted).

182 *Id.* ¶ 106.

183 Mullins, Exh. No. BGM-1CT at 53:19-54:3.

184 *Id.* at 55:4-56:5.

185 Staff Initial Brief ¶ 101.

186 *Id.* ¶ 102.

187 Twitchell, Exh. No. JBT-1T at 13:12-15.

Likewise, Mr. Mullins testifies that the Company's diverse portfolio is what matters. The RRTM's attempt to isolate cost recovery of certain generators "ignores the fact that [the Company's] overall system is benefiting as a result of the diverse nature of all the resources in its portfolio."[188] Staff concludes its contribution to this line of argument with the observation that:

> [T]he RRTM's focus on single characteristic resources is too narrow and fails to consider what really matters – the cost performance of the Company's entire resource portfolio and market purchase activities. The hypothetical costs offered by the RRTM should be rejected in favor of a full PCAM as proposed by Mr. Gomez.[189]

132 *Commission Determination:* We reject the Company's request for a "renewable tracker" for the reasons below and in light of our determination above to require Pacific Power to implement a properly designed PCAM in this case. Albeit limited in scope to only a part of Pacific Power's power portfolio, the RRTM unquestionably is a form of PCAM. Yet, again, the Company elects not to follow the straightforward direction the Commission has given it concerning the required elements for properly designed PCAM, instead proposing again a dollar-for-dollar tracker. Pacific Power fails to recognize that the "appropriate balance" to which the Commission refers in Order 05, and recognized in the Company's Initial Brief,[190] refers to the Commission's insistence on properly designed dead bands and sharing bands in any PCAM. Pacific Power purports to have addressed the Commission's requirement for balance by proposing "a more narrowly tailored mechanism in this case, the RRTM."[191] The reduced scope of this power cost tracking mechanism that has no dead bands or sharing bands, however, misses the mark.

133 Pacific Power's failure, once again, to follow the plain direction the Commission offers in its orders with regard to the requirements for an acceptable power cost recovery mechanism is reason enough for us to reject the RRTM. Pacific Power may continue to be of the opinion that "dead bands and sharing bands are poor regulatory

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[188] Mullins, Exh. No. BGM-1CT at 57:21-22 and 58:1-2.

[189] Staff Initial Brief ¶ 104.

[190] Pacific Power Initial Brief ¶ 104.

[191] *Id.*

policy," as Mr. Duvall testified in Docket UE-130043.[192] The Company, however, cannot expect success with any power cost recovery mechanism proposed in Washington that ignores the fact that requiring such bands in PCAMs *is* the regulatory policy of this Commission. We note that Pacific Power recognizes this policy in other states in which the Company does business and has a power recovery mechanism in place, because the mechanisms approved by the regulatory authorities in those states all have dead bands, sharing bands, or both.[193]

134 Pacific Power's effort to tie approval of its RRTM proposal to the Energy Independence Act and its RPS is far wide of the mark. There is nothing in the Act that requires approval of a power cost tracker to ensure that a company recovers its prudently incurred costs of complying with the RPS.

135 Another flaw in the RRTM is that it ignores the performance of Pacific Power's diverse portfolio of resources. Without considering the financial performance of Pacific Power's entire generation portfolio it is not possible to determine whether the Company under-recovers or over-recovers its power costs during any given period. In the final analysis, we agree with Staff that the Company's RRTM proposal should be rejected in favor of a full PCAM that is designed to take into account the cost performance of the Company's entire resource portfolio and market purchase activities, that appropriately balances risks between the Company and its customers, and that provides Pacific Power with a continuing incentive to focus on managing its power resources rather than arguing repeatedly that it is beyond its ability to do so.[194]

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[192] *See* Docket UE-130043, Order 05 ¶ 164 (citing and quoting in part Duvall, Exh. No. GND-1CT at 31:20-32:5).

[193] California is the only exception. *See* TR 391:16-392:3 (Cross-examination of Mr. Dalley by Ms. Davison for Boise White Paper).

[194] We note that both PSE and Avista seem to have little difficulty managing their power portfolios and power costs operating similarly diverse portfolios of power sources in the same power markets, under the same RPS standards, and subject to the same Integrated Resource Planning requirements as apply to Pacific Power in Washington. Both have power cost recovery mechanisms that have been in place for some years and that have worked quite satisfactorily over the term of their operation.

F. Rate Base Assets and Depreciation

1. End of Period Rate Base (Adjustments 8.12 – 8.12.6); Depreciation and Amortization Reserve Adjusted to December 2013 (Adjustments 6.2 - 6.2.2)

136 These proposed adjustments work in tandem. Company Adjustments 8.12 – 8.12.6 "walk forward" plant balances from December 2013 average of monthly averages (AMA) rate base to December 2013 year-end adding $22,392,711 to rate base using end-of-period (EOP) balances.[195] The associated accumulated reserve impacts are accounted for in Adjustments 6.2 – 6.2.2. The proposed adjustments reduce rate base by $17,976,136,[196] resulting in a net increase in rate base of $4,416,575 using the EOP measurement instead of AMA balances for the test year.

137 The record on this issue is spare, at best. In the Company's direct case, it consists of a single Q&A in Mr. Dalley's testimony:

> **Q. Please describe the Company's proposal for the use of end-of-period rate base balances?**
>
> A. Consistent with the 2013 Rate Case, the Company proposes to reflect electric-plant-in-service balances at end-of-period levels rather than on an average-of-monthly-averages basis. As discussed in more detail in the direct testimony of Ms. Siores, the Commission has recognized in multiple proceedings that use of end-of-period rate base mitigates regulatory lag. For example, in the 2013 Rate Case, the Commission concluded: "In this case, there is a need to address at least some of the impacts of regulatory lag on PacifiCorp. We determine

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[195] Exh. No. NCS-11 at 1.16, cols. 8.12 – 8.12.6; *see also* Exh. No. NCS-3, Page 8.0.2, ln. 57 (Total).

[196] Exh. No. NCS-11 at 1.11, cols. 6.2 – 6.2.2. We note that this is very significantly different than what the Company originally calculated (*i.e.,* $6,526,993) and express our concern that no other party apparently audited the Company's numbers with sufficient care to catch the "formula error" and bring it to our attention in response testimony. Ms. Siores corrects this adjustment to the Company's depreciation and amortization reserve account in her rebuttal testimony for Pacific Power.

that an appropriate response to address these impacts in this case is approval of PacifiCorp's use of [end-of-period] rate base."[197]

138 His reference to Ms. Siores' testimony does not take us to a more detailed discussion of the Commission's recognition "in multiple proceedings that use of end-of-period rate base mitigates regulatory lag." Rather, Ms. Siores' testimony focuses exclusively on describing the two related aspects of the EOP adjustment and observing that this is the same treatment approved in Docket UE-130043:

> **Depreciation and Amortization Reserve to December 2013 Balance (page 6.2-6.2.2)**—This restating adjustment changes the depreciation and amortization reserve from December 2013 AMA balances to actual December 31, 2013 balances. This matches Adjustment 8.12, Plant Balances to December 2013 Balance, as discussed in detail below.
>
> **Depreciation Study and Annual Depreciation (page 6.3-6.3.2)**—This restating adjustment normalizes depreciation expense and reserve in the historical Test Period to reflect both the impact of the depreciation rates approved by the Commission in Docket UE-130052 and the impact of adjusting plant balances from a December 2013 AMA basis to a year-end December 31, 2013 basis. This treatment is consistent with that approved in the 2013 Rate Case.[198]
>
> Plant Balances to December 2013 Balance (page 8.12-8.12.6)—This adjustment modifies the gross plant balances from December 2013 AMA levels to the actual December 31, 2013 ending balances. This adjustment to gross plant balances reduces regulatory lag by reflecting rate base balances at end of Test Period levels. This methodology was approved in the 2013 Rate Case. The associated accumulated reserve and depreciation expense impacts are accounted for in adjustments 6.2 and 6.3, respectively.[199]

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[197] Order 05 ¶184.

[198] Siores, Exh. No. NCS-1T at 21:13-22:2.

[199] *Id.* at 29:1-7.

139 The Company's rebuttal testimony adds little to this. Mr. Dalley simply observes that Staff and Public Counsel support the use of EOP balances for rate base in this case and that Boise White Paper opposes it because the use of EOP balances "has done little to assuage the frequency of the Company's rate filings."[200] Mr. Dalley adds that "reflecting rate base using end-of-period balances more accurately reflects the cost to serve customers in the rate-effective period," and "the Commission's willingness to use end-of-period rate base balances is an encouraging step that supports future investments."[201]

140 Staff's Mr. Ball merely recognizes that the Commission approved the use of EOP rate base in Docket UE-130043 and identifies the Company's adjustments.[202] Ms. Ramas, for Public Counsel, testifies similarly that she does not challenge the Company's use of EOP rate base to address regulatory lag and "hopefully addressing rate case frequency."[203]

141 Boise White Paper witness Mr. Mullins opposes the Company's use of EOP balances. He testifies that:

> The use of EOP balances results in a mismatch between revenues, which accrue ratably over the test period, and rate base, which, under the EOP method, is measured at the end of the test period. In addition, the Company's current practice of almost continuous rate cases mitigates the impact of regulatory lag and the need to deviate from the traditional Commission methodology using AMA rate base balances.
>
> From an accounting perspective, it violates the matching principle to use averages for revenue items, but year-end balances for rate base items. Because revenues accrue ratably over the test year, the rate base, against which operating income is compared, should also reflect the ratable period over which revenues are measured.[204]

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[200] Dalley, Exh. No. RBD3-T at 11:4-5 (citing Mullins, Exhibit No. BGM-1T at 17).

[201] *Id.* at 11:8-15.

[202] Ball, Exh. No. JLB-1T at 10:9-13.

[203] Ramas, Exh. No. DMR-1CT at 12:8-13.

[204] Mullins, Exh. No. BGM-1T at 16:11-17:2.

Mr. Mullins recommends that the Commission require the Company to use AMA rate base balances when determining revenue requirement in this proceeding.

142 Responding to Staff and Public Counsel in cross-answering testimony, Mr. Mullins testifies that use of EOP balances for rate base is an exception to the historical test period approach and "should not be the normal standard that is used by utilities in their rate filings."[205] He supports the use of AMA methodology because it is true to the matching principle. He cites to the same authority to which Pacific Power points in its brief for the point that "in normal economic times average rate base is more realistic and projects more accurately the cost of plant that produces the revenue under investigation."[206] He says there is no evidence in this record showing that the current economy is "so abnormal as to warrant an exception to the use of AMA."[207]

143 Finally, Mr. Mullins testifies that the Commission's approval of EOP rate base in 2013 apparently did not discourage the Company from "its current pattern of almost continuous rate cases."[208]

144 In its Initial Brief, Pacific Power cites to an early case for the proposition that:

> The Commission has recognized that the use of EOP rate base is an "appropriate regulatory tool under one or more of the following conditions: (a) abnormal growth in plant; (b) inflation and/or attrition; (c) as a means to reduce regulatory lag; (d) failure of utility to earn its authorized rate of return over an historical period."[209]

The Company treats this observation by the Commission over 30 years ago as a standard for approval, arguing that: "Because 'one or more' of the Commission's

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[205] Mullins, Exh. No. BGM-8T.

[206] *Id.* at 9:19-21 (quoting *WUTC v. Wash. Nat. Gas Co.,* Cause No. U-80-111, 44 P.U.R.4th 435 (Sept. 24, 1981)).

[207] *Id.* at 9:21-10:2.

[208] *Id.* at 10:3-12.

[209] Pacific Power Initial Brief ¶ 145 (citing *WUTC v. Wash. Nat. Gas Co.,* Cause No. U-80-111, 44 P.U.R.4th 435, 438 (Sept. 24, 1981); *see also WUTC v. Puget Sound Energy*, Dockets UE-111048, *et al.*, Order 08 ¶ 97 (May 7, 2012)).

conditions has been clearly satisfied in this case, the Commission should approve the use of end-of-period rate base."[210]

145 *Commission Determination:* We first address Pacific Power's argument on brief, discussed immediately above, to underscore that the early case to which it cites does not establish a standard for determining when the use of EOP rate base is appropriate. The Commission's discussion in the first recent case approving this approach provides useful context:

> The Commission has traditionally required that utility rates be established relying on the measurement of rate base using the AMA approach. The Commission, however, has occasionally recognized that the alternative approach of utilizing end-of-test period rate base may be appropriate in a variety of circumstances.[211] In a 1981 case, *WUTC v. Washington Natural Gas,* the Commission drew on its early experience evaluating the relative merits of the two approaches and drew the following conclusions:
>
> (1) Average rate base is the most favored,
>
> (2) Year-end rate base is an appropriate regulatory tool under one or more of the following conditions:
>
> (a) Abnormal growth in plant
> (b) Inflation and/or attrition
> (c) As a means to mitigate regulatory lag

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[210] *Id.* ¶ 146.

[211] *See, e.g., WUTC v. Olympic Pipeline Company,* Docket TO-011472, Twentieth Supp. Order, ¶¶ 158-160 and 370 (September 27, 2002). In an earlier case involving PSE's predecessor on the electric side of its operations, the Commission stated that:

> Historically, the commission has accepted the average rate base concept as being an appropriate tool in the measurement of earning levels. It has not, however, discounted the validity of year-end rate base where special conditions exist, such as unusual growth in plant at a faster pace than customer growth and customer rate-making treatment is deficient.

Washington Utilities & Transp. Commission v. Puget Sound Power & Light Co., 7 PUR4th 44, 50 (September 27, 1974). (rejecting end of test period rate base).

(d) Failure of utility to earn its authorized rate of return over an historical period.[212]

In the PSE cases, the Commission found that all of these "somewhat interrelated" issues were "present to one degree or another" at the point in time when the case was under consideration.[213] Importantly, too, the Commission found "ample evidence" of "earnings attrition, caused by continuing growth in capital investments" as important to its consideration of historical under earnings.[214]

146 In this case, we have some evidence of capital additions during relevant periods but it does not demonstrate abnormal growth in plant. Inflation remains very low in the current economic environment in the United States. The Company did not present persuasive evidence that it is suffering attrition in earnings. In particular, the Company did not present an attrition study. Moreover, the fact that the Company failed in the past to earn its authorized return cannot justify use of EOP absent a showing that, due to factors beyond the Company's control, the Commission can expect this condition to continue into the future. There is no such evidence in the record of this case.

147 The Commission first approved the use of EOP rate base for Pacific Power in 2013, in Docket UE-130043, observing that:

> The Commission historically has tolerated some degree of regulatory lag in its ratemaking practice, recognizing that it is a factor in encouraging utilities to operate efficiently. During recent periods, however, the impacts of regulatory lag on the ability of PacifiCorp and other utilities to earn their authorized revenue requirements have contributed to what the Commission has described as a "current pattern of almost continuous rate cases." Considering this, the Commission stated:

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[212] *Petition of Puget Sound Energy and NWEC for Decoupling Authority*, Dockets UE-12167 and UG-121705 (consolidated) and *WUTC v. Puget Sound Energy*, Dockets UE-130037 and UG-130138 (consolidated), Order 07 ¶ 45 (citing *WUTC v. Wash. Nat. Gas Co.,* 44 P.U.R. 4th 435, 438 (Sept. 24, 1981)).

[213] *Id.*

[214] *Id.* at ¶ 45.

> This pattern of one general rate case filing following quickly after the resolution of another is overtaxing the resources of all participants and is wearying to the ratepayers who are confronted with increase after increase. This situation does not well serve the public interest and we encourage the development of thoughtful solutions.[215]

Recognizing the use of EOP rate base as a means to address the problem of regulatory lag having an impact on a utility's ability earn its authorized revenue requirement today, as it last did during the period of extraordinary inflation during the 1970's and early 1980's,[216] the Commission found in Docket UE-130043 that approval of Pacific Power's use of EOP rate base was an appropriate response.[217] As the above-quoted passage from Order 05 demonstrates, however, the Commission tied its decision directly to its expectation that granting such relief would discourage Pacific Power from continuing to file one rate case after another, which the Commission found is contrary to the public interest.

148 More importantly, the Commission recognized in Order 05 that the implications of using EOP rate base vis-à-vis the matching principle were not fully developed in the record of Docket UE-103043. The Commission observed, for example, that there should be an adjustment to end-of-period revenues to maintain the integrity of the matching principle. The Commission rejected Public Counsel's proposal for such an adjustment only because:

> [I]t would be unduly complicated in the context of this case to fully explore and resolve the impacts that adoption of Public Counsel's

[215] Docket UE-130043, Order 05 ¶ 181 (quoting *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049 (consolidated), Order 08 ¶ 507 (May 7, 2012)).

[216] *See WUTC v. Wash. Nat. Gas Co.*, Cause No. U-80-111 44 P.U.R. 4th 435, 437 (Sept. 24, 1981) *(*"We have in the past decade witnessed a proliferation of rate filings and most filings have brought the differences over rate base into sharp focus.").

[217] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-130043, Order 05, ¶ 184 (December 4, 2013).

> approach would have in terms of the production factor adjustment, allocation issues, and rate spread.[218]

The Commission cautioned, however, that:

> In any future case in which PacifiCorp, or another party, proposes EOP rate base, we would expect to see a more fully developed record and a more refined approach to [ensure] there is not a resulting violation of the matching principle.[219]

149 Less than five months after the Commission published these words, Pacific Power filed this general rate case. We observe in this connection that filing rate cases essentially back-to-back means the Commission has no ability to evaluate whether the use of EOP rate base is an improvement over the AMA approach in terms of reducing regulatory lag. If we cannot meaningfully observe some benefit over time to allowing the EOP exception to our preferred approach, we are less inclined to grant the exception.

150 We are most concerned in this case that the record is woefully inadequate in terms of demonstrating "a more refined approach" that assures the Commission that the use of EOP rate base "is not resulting in violation of the matching principle." The Commission gave explicit direction to the parties concerning its expectation in this regard. Yet, Pacific Power and the other parties supporting its use of the EOP method in this case ignored this direction. Boise White Paper, on the other hand, offers both expert testimony and argument that goes to the heart of our concerns over the use of EOP rate base as the new standard.

151 We reject Pacific Power's use of EOP rate base in this case, finding that the Company has failed to meet its burden of proof on this issue, and require that the Company's compliance filing use the preferred AMA approach. We do not foreclose the possibility of approving EOP in a future case if there is an adequate showing that it promises the results we expect and is determined to be an appropriate regulatory mechanism under specific, well documented facts supporting its use.

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[218] *Id.* ¶ 185.

[219] *Id.*

2. Major Capital Plant Additions (Adjustment 8.4)

152 Pacific Power proposed as part of its initial filing to include all post-test period capital projects with a budget greater than $250,000 and planned to be placed in service between January 1, 2014, and March 31, 2015, the end of the suspension period in this case. The Company thus proposes in its initial filing the addition of 30 post-test-period projects as *pro forma* additions to rate base.[220] This proposal contrasts sharply to what Pacific Power proposed in Docket UE-130043, in which the Company sought to include only four post-test period capital additions that were all over $10 million on a Company-wide basis. Among the 30 projects included in Pacific Power's filing in this case, only one, the Merwin Project,[221] is indisputably a "major" plant addition.[222]

153 Mr. Mullins testifies for Boise White Paper that the Commission should reject the Company's proposal to include any *pro forma* capital additions in revenue requirement, with the exception of the Merwin Project. According to Mr. Mullins, removing these expenditures will result in a $3.8 million reduction to the Company's revenue requirement.[223]

154 Fundamentally, Mr. Mullins' testimony is that the Company has failed to carry its burden to present the evidence necessary for the Commission to make an affirmative determination that each of the *pro forma* projects proposed by the Company satisfies the used and useful and known and measurable standards. He states that 25 of the proposed capital additions are supported by no more than "brief narrative descriptions included in an exhibit of Ms. Siores' testimony."[224] According to Mr. Mullins, these descriptions "fall short of providing the Commission with the necessary information to determine whether these *pro forma* projects satisfy the heightened burden to be

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[220] Siores, Exh. No. NCS-1T at 26:8-13.

[221] The Commission rejected the Merwin Project as a capital plant addition in Docket UE-130043 because it was not shown to be used and useful during the time period of the case. Docket UE-130043, Order 05 ¶¶ 203-06.

[222] There is no directly applicable legal standard for what is a "major" project except in WAC 480-140-040, which establishes $3 million in total project costs as the minimum size for a project to be considered "major".

[223] Mullins, Exh. No. BGM-1CT at 2:18-22.

[224] *Id.* at 11:2-3 (citing Siores, Exh. NCS-1T at 6:1-8; Exh. No. NCS-3 at 8.4.4-9.)

included in rate base."[225] He says these are relatively small projects with changing capital budgets and "highly uncertain" timing.[226]

155 Mr. Mullins cites as an example the Yale Upper Rock Block Stabilization project. He testifies it originally was planned to be placed in service in October 2014 at a total cost of $2.7 million.[227] Yet, Mr. Mullins states, according to the Company's response to a Boise White Paper data request the planned in-service date changed to February 2015 and the total cost estimate increased to $6.2 million.[228] He says that "[m]any of the other small projects follow a similar pattern, which the Company has made no effort to explain in testimony."[229] For these reasons, he recommends that the Commission disallow the 25 projects supported only in Ms. Siores' exhibit.

156 Turning to the remaining five projects Pacific Power proposes as *pro forma* major plant additions, Mr. Mullins opposes four: 1) the Jim Bridger Unit 1 Cooling Tower Replacement Project; 2) the Union Gap Substation Upgrade; 3) the Selah Substation Capacity Relief; and 4) the Fry Substation Project.[230] The focus of his concern is what he characterizes as the uncertain costs and timing of these projects. Mr. Ralston testified as part of the Company's initial filing that the Jim Bridger project would go

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[225] *Id.* at 11:6-8.

[226] *Id.* at 11:8-11.

[227] *Id.* (citing Exh. No. NCS-3 at 8.4.2).

[228] Exh. No. BGM-4C (Pacific Power's 1st Revised Response to Public Counsel ("PC") DR 54, Attachment PC 54-1 1st Revised).

[229] *Compare* Siores, Exh. No. NCS-3 at 8.4.2 and Siores Exh. No. NCS-11 at 8.4.2 (showing revisions to all proposed capital addition costs, including significant changes on some projects, and changed in-service dates for many projects). See also Public Counsel Initial Brief ¶ 52

> [N]ot only did Pacific Power's case materially change after the initial filing, but its rebuttal contained numerous errors and required further corrections, updates which were finalized only days before hearing. In general, the later in the case information is provided, the less opportunity there is to confirm it. Rather than allowing plant additions 10½ months after the end of the test year, Public Counsel believes a more reasonable compromise is to restrict additions to those before August 31, 2014, which helps ensure that the most reliable data is being used. Approving additions up to the time of rebuttal, and with even later revisions, reduces confidence in the reliability of the data.

[230] *Id.* at 12:6-8.

into service in May 2014 at a cost of $5.9 million.[231] During discovery, the Company provided updates showing an October 2014 in-service date and a cost of $2.2 million.[232]

157 Public Counsel recommends that we allow as *pro forma* capital additions projects placed in service as of August 31, 2014, to the extent they are based on actual costs.[233] In Public Counsel's view, this is an appropriate response to regulatory lag and rate case frequency. The bright-line cut-off date of August 31, 2014, is the latest date Public Counsel believes is appropriate in terms of allowing adequate time to review, particularly considering "concern about the significant number of changes and corrections to the Pacific Power plant additions in the later stages of the case."[234] Coupled with the plant additions it supports, Public Counsel proposes a corresponding decrease to the Company's depreciation expense level for the test year to reflect plant, over $250,000 on a Washington basis retired by June 30, 2014.[235] Public Counsel contends its approach reflects the matching principle used in the test year to plant additions made after the test year.

158 Staff supports incorporating into rates plant that is in service at the time of rebuttal, provided the Company updates its *pro forma* additions with actual costs.[236] According to Ms. Erdahl's testimony, "Staff's position reflects the Commission's statements in Order 05 from Docket UE-130043."[237] She testifies further that "[i]n the Company's most recent rate case, the Commission accepted Pacific Power's end-of-period plant additions based on updated actuals as revised by the Company in its rebuttal testimony.[238]

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[231] Ralston, Exh. No. DMR-1T at 4:4-9.

[232] Exh. No. BGM-4C (Pacific Power's Response to PC DR 54, Attachment 54-1).

[233] *See generally* Ramas, Exh. No. DMR-1CT at 12:20-17:18. In direct testimony Ms. Ramas agrees to 11 *pro forma* major plant additions in service by June 30, 2014, if based on actual costs (Ramas, Exh. No. DMR-1T, at 13:25-14:2, 15:7-8, and 16:17-21.).

[234] Public Counsel Initial Brief ¶ 51.

[235] Ramas, Exh. No. DMR-1T, at 17:18- 18:3. The June 30 date is the same in-service cutoff date Public Counsel proposed for major plant additions in its initial testimony.

[236] Erdahl, Exh. No. BAE-1T, at 8:4-8; 9:1-4.

[237] *Id.* (citing Docket UE-130043, Order 05 ¶¶ 198-202).

[238] *Id.* (citing Docket UE-130043, Order 05 ¶ 201).

159 Two business days before the hearing, the Company modified its *pro forma* adjustment approach to include only plant in service by the time of rebuttal and based on actual booked costs, essentially adopting Staff's position.[239]

160 In addition to the 25 capital additions for which Ms. Siores is the only Company witness, the Company's initial case included five proposed capital additions sponsored by other witnesses. These are:

- Merwin Fish Collector Project
- Fry Substation
- Selah Substation
- Union Gap Substation Upgrade
- Jim Bridger Unit 1 Cooling Tower Replacement Project

The Merwin Project is not contested. The Company removed the Fry and Selah Substation projects, which were not in service when it accepted Staff's recommendation for a cutoff date as of November 15, 2014. Boise White Paper recommends that the Commission reject for this rate case the remaining two projects, the Union Gap Substation Upgrade and the Jim Bridger Unit 1 Cooling Tower Replacement Project.

161 Mr. Mullins testifies that the Union Gap Substation Upgrade has been divided into three distinct phases, the first of which the Company describes as a preliminary step to make room for the final two phases to be completed in 2015. Boise White Paper argues that the first phase therefore is not used and useful when considered independently.[240]

162 Mr. Vail testifies for the Company, however, that "this project is prudent and necessary to continue to provide safe and reliable service to Washington customers

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[239] Dalley, Exh. No. RBD-10CX, TR. 386:18-390:2.

[240] Mullins, Exh. No. BGM-1CTr at 14:1-8.

and to meet mandated NERC reliability standards."[241] He says, in addition, that with construction for the first phase "complete and . . . placed in service in August 2014,"[242] "all of the associated equipment, including the distribution transformers, switchgear, and related assets, will be fully used and useful to serve the local area distribution load," providing benefits "by increasing distribution capacity, replacing aged equipment, and mitigating protection system exposures."[243]

163 Mr. Mullins also recommends that we reject the Jim Bridger Unit 1 Cooling Tower Replacement Project from the major plant additions adjustment. Boise White Paper argues that the costs associated with this project "have varied so significantly as to be irreconcilable with a reasonable application of the Commission's demand for 'a high degree of analytical rigor' in order to satisfy the 'known and measurable test.'[244] This argument, however, ignores Mr. Mullins' related testimony explaining that the variability was due to errors by the Company in reporting in-service dates and costs for some projects.[245] He acknowledges that the corrected information provided by Pacific Power "more closely aligned with the Company's filing."[246]

164 According to Pacific Power, the Jim Bridger Unit 1 Cooling Tower Replacement Project was completed and put in service "in May 2014, shortly after the Company filed its case."[247] According to the Company, "there is no uncertainty regarding the final costs of the project or the project's in service date."[248]

165 *Commission Determination:* The Commission's long-standing practice is to consider post-test-year capital additions on a case-by-case basis following the used and useful and known and measurable standards while exercising the considerable discretion

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[241] Vail, Exh. No. RAV-2T at 2:14-15.

[242] *Id.* at 5:13-15.

[243] *Id.* at 2:23-3:4.

[244] Boise White Paper Initial Brief ¶ 57 (citing Docket UE-130043, Order 05 ¶ 205 (quoting Docket Nos. UE-090704 and UG-090705 (consolidated), Order 11 ¶ 26)).

[245] Mullins, Exh. No. BGM-1Tr at 13:1-9.

[246] *Id.*

[247] Pacific Power Initial Brief ¶ 126 (citing Ralston, Exh. No. DMR-1T at 4:7-9; Siores, Exh. No. NCS-10T at 18:19-19:3).

[248] Id. (citing Siores, Exh. No. NCS-10T at 18:19-23).

these standards allow in the context of individual cases.[249] This approach provides the Commission with flexibility when evaluating relevant factors without being confined by "too rigid an approach" through a consistent, bright-line standard.[250]

166 The Commission has made clear in prior orders that when the Company proposes a *pro forma* addition to rate base it has the burden of proof to show that resources allocated to Washington are "used and useful for service in this state."[251] This means that the Company must demonstrate "quantifiable" benefits to ratepayers in Washington for each and every resource to be included in rates.[252]

167 As recently as the Company's 2013 GRC, the Commission reiterated its definition of the known and measurable standard applicable to capital additions:

> The known and measurable test requires that an event that causes a change in revenue, expense or rate base must be known to have occurred during, or reasonably soon after, the historical 12 months of actual results of operations, and the effect of that event will be in place during the 12-month period when rates will likely be in effect. Furthermore, the actual amount of the change must be measurable. This means the amount typically cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base. There are exceptions, such as using the forward costs of gas in power cost projections, but these are few and demand a high degree of analytical rigor.[253]

168 We now turn to the bright line standards advocated by Public Counsel and Staff in this case (*i.e.,* respectively, August 31, 2014, and the date of Pacific Power's rebuttal filing, November 15, 2014). In this regard, it is useful to recall the guidance the Commission provided in the Company's prior GRC:

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[249] *See* Docket UE-130043, Order 05 ¶ 198.

[250] *Id.* ¶¶ 198-99.

[251] *See WUTC v. PacifiCorp,* Docket UE-050684, Order 04 ¶ 49 (April 17, 2006).

[252] *Id.* ¶ 51.

[253] Docket UE-130043, Order 05 ¶ 205 (December 4, 2013) (quoting *WUTC v. PSE*, Dockets UE-090704 and UG-090705, Order 11 ¶ 26 (Apr. 2, 2010)).

> Staff's idea that the Commission should have "a consistent and practical" "bright line" standard when evaluating what is "known and measurable" or "used and useful," though providing for some certainty in future application, is too rigid an approach. The Commission requires flexibility in most cases to exercise its informed judgment in ways that respond adequately and appropriately to the dynamic economic and financial circumstances that are characteristic of the utility industry and the general economy. Just as there are times when it is appropriate to depart from the preferred use of AMA rate base, as discussed above, there are times when it is appropriate to be more flexible in allowing post-test period *pro forma* adjustments and times when it is appropriate to be less flexible.
>
> In sum, we reject the bright line cutoff dates proposed respectively by Staff and Public Counsel.[254]

While the Commission accepted three *pro forma* additions in 2013 based on updated actuals, as revised by the Company in rebuttal, it is clear from the discussion quoted above that the timing of the updates had nothing to do with the Commission's decision. Rather, the acceptance of these adjustments was based on the Commission's flexible exercise of discretion in applying its informed judgment to the record, and to its determination that it was appropriate "to be more flexible in allowing post-test period *pro forma* adjustments" in the specific context of the case before it.

169 Having just rejected the use of a bright-line cutoff date for the acceptance of post-test period additions to rate base and having just reiterated the Commission's standard for considering whether to allow such additions, we are confronted in this case with Staff and Public Counsel advocating bright-lines and the Company more or less ignoring the used and useful and known and measurable standards. The record in this case demonstrates why the Commission requires a more rigorous record and increasingly concrete support for *pro forma* adjustments the later in time plant additions are put in service and claimed to be used and useful. In this case the Company presents scant data concerning most of its proposed post-test period adjustments and the quality of its data has been shown to be poor and subject to revisions. Both cost and in-service date data presented in the original filing proved to be quite inaccurate for some

[254] *Id.*, Order 05 ¶¶ 199-200.

projects. In addition, neither Staff nor Public Counsel present any evidence that they actually audited the data presented at any point in time. While Public Counsel's analyses during the case uncovered numerous errors in the data the Company presented the analysis was not an audit-level review. The Company's evidence and other parties' review falls far short of what we require to determine whether a proposed plant addition is used and useful and that its costs are known and measurable.

170 We also note that the relative size of many of the Company's proposed plant additions in this case falls short of any reasonable definition of "major" and there is no discussion in the record concerning possibly offsetting factors that may have occurred coincident with any of the plant going into service. In other words, neither the Company, nor any of the parties, appear to have taken into serious consideration the requirement to consider the matching principle for such capital additions.

171 Accordingly, we reject the *pro forma* plant additions to rate base for 25 of the 30 relatively small projects, described briefly in Ms. Siores revenue requirements exhibit as being insufficiently supported by the evidence.[255] The brief descriptions of these 25 projects, supported by another two pages of data showing anticipated in-service dates and cost estimates, simply do nothing to establish that the projects should be added to rate base. The problems associated with not having accurate in-service dates or costs that can be considered known and measurable for these projects are illustrated by Mr. Mullins' example of the Yale Upper Rock Block Stabilization project, by his unrebutted testimony that similar problems plague the data displayed in Ms. Siores' revenue requirements exhibit, and by the fact that the Company found it appropriate to remove a number of projects immediately prior to our evidentiary hearing in this docket.[256]

172 Of the remaining five projects, the Company withdrew consideration of the Fry and Selah Substation projects, and the Merwin Project is not contested. Turning to the two remaining plant additions that are contested, the Union Gap Substation Upgrade and the Jim Bridger Unit 1 Cooling Tower, we find the Company satisfactorily demonstrated that both projects are used and useful and that their costs are known and measurable. Phase 1 of the Union Gap project met these criteria by August 2014, well in advance of the date for response testimony. The Jim Bridger project went on

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[255] *See* Exh. No. NCS-3 at 8.4.4 – 8.4.9.

[256] *See* Exh. No. RBD-10CX; TR 386:18-390:2.

line even earlier, in May 2014. Accordingly, we accept the post-test year plant additions in rate base for the three projects mentioned above, including the uncontested Merwin Project.

3. Depreciation Study and Annual Depreciation (Adjustments 6.3 - 6.3.2 and 6.5)

173 Public Counsel proposes an adjustment to reflect the reduced depreciation expense associated with *pro forma* major plant retirements in determining revenue requirement.[257] The Company agrees that this adjustment is appropriate for purposes of this case and developed Adjustment 6.5 (Retired Assets Depreciation Expense Removal) to reflect the removal of depreciation expense associated with major plant retirements exceeding $250,000 on a Washington-allocated basis.[258] According to Ms. Siores, "based on the most recent asset retirement information available," including tax impacts, this adjustment decreases Washington revenue requirement by approximately $29,000. The Company proposes to update this adjustment in its compliance filing to reflect the depreciation expense impact of actual major plant retirements before the rate effective date to maintain consistency with the Company's proposed treatment of *pro forma* major plant additions.[259]

174 *Commission Determination:* This adjustment, to which Pacific Power and Public Counsel agree, appears to rest on the predicate that the Commission accepts the plant additions to which the Company and Staff agree. We do not, as discussed in the preceding section of this Order. We do not foreclose Pacific Power from recognizing this adjustment in its compliance filing, but we do not require it to do so.

G. "Fall-Out" Adjustments

175 We recognize two so-called fall-out adjustments, interest true up (Adjustment 7.1) and Production Factor (Adjustment 9.1). The amounts of these adjustments turn entirely on decisions concerning contested revenue requirements. The method for determining them is not disputed. It is the Commission's practice, however, to include these in the table of contested adjustments included as an appendix to this Order. We will do so again in this case.

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[257] Ramas, Exhibit No. DMR-1CT at 17:19-19:8.

[258] Siores, Exh. No. NCS-10T at 11:16-12:3.

[259] *Id.* at 12:4-7.

H. Capital Structure and Cost of Capital

176 Pacific Power and other parties presented in the Company's 2012/2013 GRC, Docket UE-130043, the full panoply of evidence typically filed in cases where the Company's capital structure, cost of equity, and overall weighted cost of capital (*i.e.,* overall rate of return, or ROR) are contested. The Commission determined the issues on their merits, as discussed in detail in the Commission's Final Order in the case.[260]

177 Pacific Power filed a petition for judicial review of Order 05, as discussed above in connection with the issue of the allocation of QF power costs. In its petition, the Company also challenges the Commission's determination of cost of capital, focusing specifically on the Commission's rejection of Pacific Power's argument that the Commission must rely on the capital structure of PacifiCorp, the Company's corporate parent, as a surrogate for Pacific Power's "actual capital structure" when, in fact, Pacific Power has no capital structure of its own.[261]

178 Yet, in the present case, filed just five months after the Commission entered its final order in Docket UE-130043, Pacific Power has put forward a full cost of capital case. Staff, Public Counsel, and Boise White Paper, in response, each put on full cost of capital cases and all parties fully briefed the issues. The only difference between the capital structure proposed in this case and the previous one, now subject to judicial review, is a slight change in the level of equity proposed (*i.e,* 51.73 percent) because "the Company used an average of PacifiCorp's five-quarter ends spanning the

[260] Docket UE-130043, Order 05 ¶¶ 22-73. The Commission devoted 21 pages to the analysis and discussion of cost of capital issues, more than 20 percent of the 97 pages of substantive discussion included in Order 05.

[261] TR. 178:2-7 (cross-examination of Mr. Williams by Public Counsel). We note Mr. Williams' testimony that "it's not an apt comparison to compare the holding company [Berkshire Hathaway Energy or BHE] to PacifiCorp" because "much of the financing that Berkshire Hathaway, the ultimate parent company, has provided to BHE is in the form of debt that's structured to receive equity credit from the rating agencies." The Commission will explore in the Company's next case whether it is also true that some part of the capital that BHE has provided to PacifiCorp is actually debt yet reflected in PacifiCorp's capital structure as equity.

12 months ending December 31, 2014,"[262] instead of "the five-quarter end spanning the 12 months ending June 30, 2013"[263] used in Docket UE-130043.

179 In Docket UE-130043, Pacific Power argued that its weighted cost of capital should be based on a 10.0 percent rate of return on equity (ROE), its actual long-term debt costs and its actual costs of preferred stock.[264] The Company argued that its capital structure should not include short-term debt. The Commission, based on a detailed analysis of the full record, determined that "[t]he Company failed to carry its burden in this case to support its proposed 10.0 percent return on equity," and authorized a 9.5 percent ROE.[265] The Commission authorized a 49.1 percent equity layer based on a hypothetical capital structure for the Washington-jurisdictional rate base. Also, in that case, the Commission agreed with the Company's actual costs for long-term debt and preferred stock, and did not impute short-term debt into the capital structure.

180 In this case, Pacific Power argues again that its weighted cost of capital should be based on a 10.0 percent ROE, its actual long-term debt costs and its actual costs of preferred stock. The Company "continues to believe that it is inappropriate and inequitable to include short-term debt in the capital structure for Pacific Power," but "included projected quarter-end short-term debt balances for the period ending December 31, 2014."[266] The imputation of short-term debt, like the use of actual preferred stock data, however, has no practical impact on the weighted cost of capital (*i.e.,* overall rate of return) determined for setting rates, which we round to two decimal places.[267]

181 The level of equity in Pacific Power's capital structure (i.e., the "equity ratio") and the ROE are the only contested issues on the subject of cost of capital in this docket. The Commission resolved these issues on a full record in Docket UE-130043 in December 2013, just months before the Company filed this general rate case in May 2014. Although the parties presented evidence on these issues, we determine that this

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[262] Williams, Exh. No. BNW-1T at 4:17-18.

[263] Docket UE-130043, Order 05 ¶ 35 (quoting Williams, Exh. No. BNW-1T at 12:12-19).

[264] *Id.* ¶ 43.

[265] *Id.* ¶¶ 63, 70.

[266] Williams, Exh. No. BNW-1T at 5:9-22.

[267] *See Id.* at 23, Table 8.

evidence does not demonstrate any significant change in capital markets, or in the Company's ability to access such markets, that would justify rehearing them in this case. We therefore exercise our discretion under RCW 80.04.200 not to rehear these so recently resolved issues in this proceeding.[268]

182 We refrain from rehearing these issues, in addition, because we should not risk disrupting the Court of Appeal's orderly consideration of Pacific Power's appeal of Order 05 in Docket UE-130043 on the issue of capital structure. The equity ratio in the Company's capital structure and its allowed ROE are inextricably intertwined issues as components that go into determining the Company's overall rate of return that is used in determining revenue requirements.[269] Given that it is the overall return that defines the "end result" that is the rate regulatory goal, we should await any direction the Court of Appeals may give on capital structure before revisiting the related issue of cost of equity.[270] The Company's return on equity will remain at 9.5 percent for purposes of this case.

183 With respect to the remaining components of the Company's capital structure and costs, the issues are uncontested. We adjust the Company's long-term debt ratio to reflect our decision not to revisit the equity ratio and in light of our acceptance of the Company's as-filed ratios and costs for short-term debt and preferred stock. Thus, the Company's capital structure and cost of capital for purposes of setting rates in this proceeding are as illustrated in Table 2.

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[268] *US West Communications, Inc. v WUTC,* 134 Wn.2d 74 (1997); *see supra* ¶ 75, n. 98.

[269] Goodman, in his treatise, observes that "[t]he adopted capital structure is the 'glue' that holds together the overall cost of capital and resulting rate of return." Leonard Saul Goodman, The Process of Ratemaking, 648 (1998). We disagree with Mr. Williams' testimony that rejection of the Company's parent corporation's capital structure means the Commission should put a hypothetical cost of debt into that structure in lieu of the Company's actual costs of debt. His testimony, however, illustrates the point that different equity ratios included in the capital structure *may* affect the Commission's determination of the cost of equity, which is arrived at indirectly, in contrast to debt costs that are observed directly. *See* Williams, Exh. No. BNW-1T at 10:14-17: "While the Company's primary recommendation is based on its actual capital structure, the Company is also proposing an alternative hypothetical capital structure that includes a reduced equity component, but also reflects the impact of that change on the costs of debt and equity."

[270] *See Fed. Power Comm 'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 602-03 (1944).

TABLE 2 Capital Structure and Cost of Capital			
	Share	**Cost**	**Weighted Cost**
Equity	49.10%	9.50%	4.67%
Long-Term Debt	50.69%	5.19%	2.63%
Short-Term Debt	00.19%	1.73	0.00%
Preferred Stock	00.02%	6.75%	0.00%
OVERALL Rate of Return			**7.30%**

I. Summary of Revenue Requirement Determinations

184 Appendix A to this Order shows the Commission's determinations of the contested adjustments discussed above. Appendix B shows the uncontested adjustments, which we approve without the need for further discussion. Based in part on these adjustments, we portray in Table 3 the revenue requirement that we approve for recovery in rates.

TABLE 3 Revenue Requirement	
Rate Base Rate of Return	\$818,890,931 7.30%
Net Operating Income (NOI) Requirement *Pro Forma* NOI	\$59,779,038 53,850,896
Operating Income Deficiency Conversion Factor	\$5,928,142 0.61955
Gross Revenue Requirement Increase	\$9,568,464

J. Rates to Customers

1. Cost of Service Study

a) Classification of Generation and Transmission Costs

185 Pacific Power proposed in its cost of service study (COSS) in Docket UE-130043 to use what is generally known as the Peak & Average (P&A) method to classify generation and transmission plant as "demand-related" or "energy-related."[271] This replaced the Peak Credit methodology previously approved for the Company. Mr. Watkins, testifying for Public Counsel, discusses that:

> The P&A and Peak Credit methods are distinctly different both conceptually as well as mathematically. The P&A and Peak Credit methods both recognize energy usage and peak load (demand). However, the Peak Credit method, also known as the Equivalent Peaker method in other jurisdictions, combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal costs studies, whereas the P&A method is strictly an embedded (historical) cost allocation approach.[272]

186 The Commission approved use of the P&A method as part of a partial settlement in the 2013 case with the expectation that the issue would be revisited here.[273] Company witness Ms. Steward uses the same calculation in this case as used in the Company's 2013 Rate Case employing the WCA system diversified load factor (SDLF) to determine the proportion of generation and transmission costs that are demand related. This results in 43 percent of generation and transmission costs classified as demand related and the remaining 57 percent of costs classified as energy related.

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[271] We note that in Pacific Power's 2013 general rate case, the Company referred to this methodology as a "Revised Peak Credit" method. The P&A method was adopted as part of a partial settlement in that proceeding.[271]

[272] Watkins, Exh. No. GAW-1T at 9:1-7.

[273] Docket UE-130043, Order 05 ¶ 251; *see generally Id.* ¶¶ 242-251.

187 Public Counsel does not oppose the use of the P&A method but disagrees with the number of coincidental peak (CP) hours the Company uses in its P&A method. Public Counsel is concerned about the "reasonableness and stability" of the Company's reliance on the single highest hour of system peak (1-CP) to classify costs to demand.[274] Public Counsel recommends using instead the Company's 2013 IRP Update, or in the alternative 4-CP, 6-CP, or 8-CP.[275] Table 4 shows the results of these alternative methodologies.

Table 4

Party Proposing & Method of Calculation	Year	Demand	Energy
Company's 1-CP	2014 GRC	43%	57%
Public Counsel's IRP Update	2014 GRC	28%	72%
Peak Credit	2014 GRC	35%	65%
Company's 1-CP	2013 GRC	38%	62%

188 Ms. Steward testifies that use of the IRP data is not appropriate because the IRP "looks at the loads of the west control area at the time of the Company's entire system peak, while the Company's studies look at only WCA peak."[276] Thus, the difference in the IRP coincident peaks and the peak used by the Company are explained simply by the fact that the Company-wide peak and the WCA peak occur at different times.[277] Using Public Counsel's preferred approach would shift costs from lower load-factor customers (*i.e.,* residential customers) to higher load factor customers (*i.e.,* industrial and large general service customers).[278]

189 Boise White Paper does not support the Company's use of any type of peak credit method to classify generation costs. Instead, it proposes that the Company classify all fixed generation costs as demand-related, and all of the variable generation costs as energy-related.[279] Boise White Paper witness Mr. Stephens testifies, however, that if the Commission approves a peak credit method, it should use a 2-CP, 3-CP, or 4-CP

[274] Watkins, Exh. No. GAW-1T at 11:10-15.

[275] *Id.* at 12:12-18.

[276] Steward, Exh. No. JRS-13T, 6:15-22.

[277] *Id.*

[278] *Id*. at 7:1-9.

[279] Stephens, Exh. No.RRS-1T at 17:1-18:2.

factor for demand related production costs.[280] Mr. Stephens testifies further that there is no justification for using an energy component in allocating transmission costs.

190 *Commission Determination:* The Commission has long preferred the Peak Credit methodology and consistently has approved its use in cost of service studies for Pacific Power, and for both PSE and Avista. Mr. Watkins for Public Counsel and Mr. Stephens for Boise White Paper explore this topic in some detail. Mr. Watkins does not oppose the P&A methodology the Company uses here, as it did in its 2013 GRC, but recommends several alternative adjustments in its application. Mr. Stephens opposes the P&A and the Peak Credit methodologies and suggests additional alternatives. Mr. Watkins, moreover, discusses that there are numerous methodologies that suggests different classification and allocation approaches related to demand.[281]

191 We are not persuaded by the record in this case that we should reject Pacific Power's approach to classification of generation or transmission costs. Hence, we accept the continued use in this case of the P&A method approved and adopted as part of a settlement in the previous GRC. However, the parties raise sufficient concerns to persuade us that the Company should return in its next case to using the Commission-approved Peak Credit method or provide a more detailed justification for using an alternative approach, or approaches including the use of Peak and Average method compared to the Peak Credit method, as well as consideration of the number of hours that should be used within these methods.

b) Allocation of Demand Classified Generation and Transmission Costs to Customer Classes

192 After classifying costs, the next step in a COSS is to allocate costs. The Company's allocation of demand-classified generation and transmission costs to customer classes

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[280] *Id.* at 19:5-8.

[281] According to Mr. Watkins:

> The current National Association of Regulatory Utility Commissioners ("NARUC") *Electric Utility Cost Allocation Manual* discusses at least 13 embedded demand allocation methods, while Dr. James Bonbright notes the existence of at least 29 demand allocation methods in his treatise *Principles of Public Utilities Rates*.

Watkins, Exh. No. GAW-1T at 6:13-18.

is based on the top 100 hours in summer and top 100 hours in winter, sometimes called the 200 Coincident Peak (CP) methodology.

193 Boise White Paper argues against this approach and in favor of a method that considers only the hourly demands that are reasonably close to the system peak. Mr. Stephens testifies in this regard that:

> By considering only the hourly demands that are reasonably close to the annual system peak, the cost analyst recognizes that it is only during the highest system load hours that production capacity is most likely to be fully utilized. Consequently, a demand allocation method that is based on each class's contribution during these high demand periods will fairly and reasonably recognize the classes' proportionate responsibility in causing the utility to incur those production investments.[282]

Boise White Paper proposes using the highest two monthly load hours in summer and winter months (*i.e.,* a 4-CP method).[283] Public Counsel argues that Boise White Paper's proposal ignores the trade-offs that utilities make when deciding to build base load plants or peaker plants; because this trade-off exists, generation must be classified as partially demand and partially energy-related.[284] Public Counsel also notes that Boise White Paper's proposal represents a departure from Commission precedent dating back to 1981.[285] Similarly, the Company cites to Pacific Power's 2010 GRC in which ICNU proposed to use the same 4-CP method. The Commission rejected that proposal, saying:

> As we have in the past when presented with a precise revision to peak demand, we conclude that this is too narrow a range. We agree with PacifiCorp that ICNU's proposal could produce volatility in results depending on the test period. While it is reasonable to allocate the costs of peaking resources based on the hours those resources will actually be used to serve load, the allocation method should be flexible

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[282] Stephens, Exh. No.RRS-1T at 9:7-14.

[283] *Id. at* 11-12.

[284] Watkins, Exh. No. GAW-6T at 13:7-14:3.

[285] *Id.* at 2 (note 1).

enough to incorporate the variable peaks experienced in Washington. PacifiCorp experiences both a summer peak and a winter peak, and its proposal to include 100 summer hours and 100 winter hours to determine peak demand recognizes how resources are used.[286]

194 *Commission Determination:* The Commission has found it appropriate for some time to use the 200 CP method to allocate Pacific Power's generation and transmission costs considering how the Company's resources are used to serve customers in Washington. We find insufficient basis in the current record to depart from this approach.

c) *Corporate Account Manager Expenses*

195 Staff and Public Counsel recommend the direct assignment of costs associated with corporate account managers for industrial customers that take service under Pacific Power's Tariff Schedule 48T.[287] Pacific Power does not oppose this change, but does not include the proposal in its COSS because of the minimal impact.[288] Boise White Paper does not support this proposal, asserting that, as a matter of fairness, Schedule 48T customers are assigned costs related to residential customer service (*i.e.*, call centers) from which they receive no benefit.[289]

196 *Commission Determination:* While there is merit to the idea of directly assigning costs that are easily identified to specific customer, Boise White Paper's fairness argument also has merit. Thus, were we to make the change Staff and Public Counsel recommend, we would also need a record to show what specific customer service costs might be demonstrably inappropriate to allocate to industrial customers. Without such a record, we find it appropriate to retain the status quo and reject Staff and Public Counsel's recommendation.

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[286] *WUTC v. PacifiCorp*, Docket UE-100749, Order No. 06 ¶¶ 104-105 (Mar. 25, 2011).

[287] Watkins, Exh. No. GAW-1T at 15:8-20.

[288] Steward, Exh. No. JRS-1T at 12:9-13:1.

[289] Stephens, Exh. No. RRS-9T at 5:13-6:12.

2. Rate Spread

197 A utility performs a COSS to determine its cost to serve each class of customers. The primary result of the study is a parity ratio, calculated by dividing the revenue collected from each customer class by the cost to serve that customer class.[290] As a general matter, it is appropriate from case to case to move the rates of each customer class closer to parity. Changes in rates to effect greater parity, however, must take into account "fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability."[291]

198 *Pacific* Power presents its rate spread proposal through Ms. Steward's testimony.[292] She explains that the Company, relying on its COSS, proposes to: (1) allocate an increase based on one-half of the overall 8.5 percent proposed increase in revenue (*i.e.,* 4.2 percent) to rate Schedules 24 (Small General Service), 40 (Agricultural Pumping), and lighting schedules because the cost of service study indicates parity ratios for these customers that show they are paying more than the cost of serving them. The Company proposes that the remaining increase should be spread equally to the remaining rate schedules, which results in a 9.5 percent increase for those schedules.

199 Public Counsel accepts the Pacific Power rate spread recommendation for base rate revenue allocation (rate spread).[293] According to Public Counsel:

> The Company proposal reflects movement towards allocated costs under Ms. Steward's COSS. It also reflects the principle of gradualism

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[290] A parity ratio is one measure of whether a customer class is paying the approximate amount needed to cover its share of costs. A parity value of one means that a customer class is paying the approximate amount to cover its share of costs.

[291] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08, ¶ 350 (May 7, 2012).

[292] Steward, Exh. No. JRS-1T at 13:8-15:9; Exh. No. JRS-13T at 17:1-19:14.

[293] Public Counsel Initial Brief ¶ 102 (noting that at the Company's original revenue requirement of $27.2 million, this would result in the Residential class receiving an increase of 9.5 percent and the Small General class receiving 4.2 percent. At the Company's final revenue requirement number of $31.9 million, the Residential class increase would be 11.2 percent, and 13 percent if deferral requests are included. Steward, Exh. No. JRS-16 at 3).

> in that the Residential class will sustain a somewhat larger increase than the overall system average (8.5% under the original request) and the Small General Service a smaller increase. The percentage increase would be scaled back proportionately if, as requested by Public Counsel and other parties, the overall increase is less than the amount requested by the Company.[294]

200 As illustrated in Table 5 below, alternative proposals by Boise White Paper and Walmart are in most respects quite similar to the Company's proposal.

Table 5
Rate Spread Proposals

Schedule	Company's Proposal	Boise's Proposal	Wal-Mart's Proposal	Staff's Proposal
16, Residential	112%	112%	112%	150%
24, Small General Service	50%	45%	68%	0%
36, Large General Service <1 MW	112%	112%	100%	70%
48T, Large General Service >1 MW	112%	112%	100%	100%
48T, Dedicated Facilities	112%	112%	112%	150%
40, Agricultural Pumping	50%	71%	68%	0%
Street Lighting	50%	55%	50%	0%

201 Staff is the outlier, recommending, among other things, that the Residential class contribute 150 percent of the system average percentage increase, while small general service customers bear none of the increase. Staff's proposal is to bring each schedule's rates within 5 percent of parity in a single move.

202 *Commission Determination:* Staff's proposal would certainly move the rate spread toward greater parity in a single move. However, it fails to take into account the other factors the Commission has identified as necessary considerations when making

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[294] *Id.*

changes in rate spread: fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability. Indeed, in Pacific Power's 2010 GRC the Commission found that increases of 114 percent of the average were too extreme.[295] The other parties' proposals effectively present a more measured move in the direction of greater parity, capping the disproportionate increases to residential and other customer classes at 112 percent of the average increase. On balance, while we appreciate Staff's efforts to move quickly toward greater parity, we believe the Company's proposal comports best with principles the Commission has enunciated in prior orders. We therefore accept the Company's proposal in this case.

3. Rate Design

a) Residential Rates

203 Pacific Power proposes to increase the residential basic charge for Schedule 16 customers from $7.75 per month to $14.00 per month, an 81 percent increase from the current level. The Company would make an exception for Schedule 17, which sets rates for qualifying customers under the Company's Low Income Bill Assistance (LIBA) Program, increasing the basic charge by one dollar to $8.75. Ms. Steward testifies that the Company's embedded cost of service results supports an even higher basic charge of $28.00 per month.[296] This figure includes distribution system fixed costs (line transformers, poles, and wires), now recovered in volumetric rates, as well as the traditional costs included in basic charges that vary based on the number of customers served (service drops, meters, meter reading, and billing).[297] Ms. Steward implies that all fixed costs are appropriate for inclusion in the basic charge, including transmission and generation, which would raise the charge even more, to $47.00 per month.[298]

204 Staff proposes increasing the basic charge to $13 to allow the company more stable revenues and in support of its proposal to add a third volumetric block to encourage conservation and distributed generation (DG).[299] Staff reaches its proposed $13 basic

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[295] *WUTC v. PacifiCorp,* Docket UE-100749, Order 06, ¶ 315 (March 25, 2011).

[296] Steward, Exh. No. JRS-1T at 19:1-18.

[297] *Id.* at 19:1-18.

[298] *Id.* at 19:7-9.

[299] Twitchell, Exh. No. JBT-1T at 4:10-19.

charge by including the cost of line transformers, a distribution system cost previously included in energy rates.[300]

205 Public Counsel, TASC, and the Energy Project all offer testimony that the basic charge should include only costs that vary based on the number of customers served.[301] Public Counsel and TASC argue, based on the traditional "direct customer cost" analysis and a Regulatory Assistance Project paper, that transformer costs vary based upon demand and should be included in energy rates.[302] Public Counsel and TASC also argue that the Company's increase in the basic charge violates the regulatory principle of gradualism and is contrary to conservation efforts.[303] Mr. Watkins, for Public Counsel calculates that using traditional "direct customer cost" analysis, the basic charge should be between $7.31-7.50.[304] Mr. Fulmer, for TASC, supports a basic charge of $9.00.[305] Mr. Eberdt testifies that the Energy Project opposes an increase to the basic charge for all customers.[306]

206 *Staff* supports its proposed increase in the basic charge by reasoning that "in the absence of a decoupling mechanism to reduce Pacific Power's risk of under-recovering fixed costs due to declining load, it is appropriate to shift the distribution of the Company's cost recovery toward fixed sources of recovery, such as the monthly basic charge."[307] Mr. Fulmer, for TASC, points out that increasing the basic charge would discourage distributed generation, and that decoupling, attrition adjustments, minimum bills and forward-looking test years are more appropriate ways to address utility revenue deficiency than higher fixed charges.[308] Staff agrees with

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[300] *Id.* at 26:21-27:7.

[301] Watkins, Exh. No. GAW-1T at 27:1-30:22; Fulmer, Exh. No. MEF-1T at 6:1-8:2; Eberdt, Exh. No. CME-13 at 10.

[302] Fulmer, Exh. No. MEF-1T at 9:17-21 (note 9) (*citing* Weston, Frederick, "Charging For Distribution Utility Services: Issues In Rate Design," the Regulatory Assistance Project. (December 2000)).

[303] Watkins, Exh. No. GAW-1T at 17:17-21; Fulmer Exh. No. MEF-1T at 10:3-12:16.

[304] Watkins, Exh. No. GAW-1T at 27:15-20.

[305] Fulmer, Exh. No. MEF-1T at 3:3-4.

[306] Eberdt, Exh. No. CME-1T at 21:17-22:16.

[307] Twitchell, Exh. No. JBT-1T at 26:15-18. Pacific Power provides a similar argument in support of revenue stability. *See* Steward Exh. No. JRS-1T at 19:19-21:17.

[308] Fulmer, Exh. No. MEF-1T at 12:20-28.

TASC on this point, stating in its Initial Brief that it is curious that Pacific Power did not request a decoupling mechanism in this case. Staff argues that "[t]he decoupling mechanisms recently approved by the Commission provide the affected utilities a guaranteed amount of revenue, regardless of actual retail sales."[309] In Staff's view, a decoupling mechanism would provide the Company more certainty of cost recovery than do other approaches.

207 Staff combines an increase in the basic charge with the addition of a third volumetric block to Pacific Power's residential rates in order to:

- Provide the Company more reliable recovery of fixed costs.
- Establish clear price signals for consumers that support energy efficiency and distributed generation.

208 *The* bases for Staff's three-block proposal are:

- Block 1 to correspond to inelastic use,
- Block 2 to reflect average use, and
- Block 3 to assign a greater share of the increase to high-use customers and not impose additional costs on average users.[310]

Staff proposes this new structure to send a price signal that encourages conservation among customers with discretionary, or elastic, electricity use. Staff attempts to set the first volumetric block to cover a typical customer's inelastic consumption, thereby placing discretionary use in the second and third volumetric blocks.[311]

209 Relying on a U.S. Dept. of Housing and Urban Development (HUD) guidebook, Staff believes that the first 800 kWh of residential usage is inelastic because it represents use for essential needs (e.g., cooking, domestic hot water, lighting, and home

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[309] Staff Initial Brief ¶ 117 (citing Twitchell, Exh. No. JBT-1T at 24:5-11; *see* Dockets UE-140188 and UG-140189, Order 05).

[310] Twitchell, Exh. No. JBT-1T, at 12:28-29.

[311] *Id.* at 28:1-13.

appliances).[312] Using data from its 2013 IRP the Company argues that the amount of electric energy use for the most common types of appliance and lighting load in a home is under 600 kWh per month.[313] This 600 kWh excludes electric heating, which is present in 56 percent of homes in the Company's service territory.[314]

210 Staff witness Mr. Twitchell estimates that the addition of the third block could result in as much as 7,660 MWh of savings annually, or 14 percent of the company's average annual conservation savings.[315] The Company claims that its rate design will result in 2 percent more conservation because a higher volumetric rate (from sales in the larger second block) would apply to more kWh sales.[316]

211 Under Staff's proposal, most customers with average use will see a bill decrease, while low use and high use customers will see a bill increase. The Company argues that lower bills for most customers mean that Staff's proposal does not encourage conservation.

212 The Company does not believe that Staff's rate design will improve its revenue stability because it will recover 22 percent of its revenue from the third block, in contrast to its own rate design, which will recover 18 percent of revenues from use over 1,700 kWh.[317] The Company argues that as a result of Staff's proposal, variances in weather will result in larger variances in revenues.[318]

213 Mr. Eberdt testifies that "the Energy Project opposes any increase to the monthly residential basic charge until such time as more thorough data is available and analyzed regarding the true number and nature of PacifiCorp's low income customers and their energy consumption."[319] Some low-income customers are relatively high

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[312] *Id.*

[313] Steward, Exh. No. JRS-13T at 44:15-20.

[314] *Id.* at 45 (Table 14).

[315] Twitchell, Exh. No. JBT-1T at 33:8-11. The estimate was developed using state-specific price elasticity data from a 2006 National Renewable Energy Lab study. *Id*.

[316] Steward, Exh. No. JRS-21; Steward Exh. No. JRS-13T at 39:9-12.

[317] Steward, Exh. No. JRS-13T at 39:23-40:2.

[318] *Id.* at 40:3-17.

[319] Eberdt, Exh. No. CME-1T at 24:2-5.

users in the winter months, not by choice, but because of poor housing stock and an inability to finance conservation measures such as insulation and more efficient heating. To these customers, an increased basic charge coupled with a third tier rate will mean increases in monthly bills to customers who can least afford it.[320] At the other end of the low-income spectrum, very low volume users will experience significantly higher bills and a disproportionate impact from an increased basic charge. Because of these impacts, the Energy Project supports raising the upper end of the first block from 600 to 800 kWh, but thinks the beginning of the third block should be higher than 1,700 kWh. Mr. Eberdt argues that many low-income customers would be subject to third block rates in the winter, "running the risk of greater shut-offs and less revenue recovery than expected."[321] Mr. Eberdt provides data that shows in two months, January and December 2013, average low-income use was about 2,200 kWh and would result in higher bills under Staff's proposal; in all other months average low-income use was in the range that will result in bill reductions.[322]

214 *The* Energy Project argues that the Company's proposal to increase the basic charge by only $1.00 for low income customers who receive benefits under either LIHEAP or LIBA does not recognize the scope of the problem increased basic charges pose for the low-income population.[323] The Energy Project points to Staff witness Mr. Kouchi's testimony that the LIHEAP/LIBA recipients to whom Schedule 17 applies constitute only 5.6 percent of the Company's residential population, yet the poverty levels in Pacific Power's Yakima and Walla Walla service areas might be as high as 23 percent to 38 percent respectively.[324] "Thus, limiting the basic charge increase to only those customers already receiving some form of assistance hardly scratches the

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[320] Energy Project Initial Brief at 7.

[321] Eberdt, Exh. No. CME-8T at 3:14-17. This is because low-income households rely on electric resistance for space and hot water heating more than other customers. *Id*., 4:1-13.

[322] Eberdt, Exh. No. CME-13.

[323] *See* Eberdt, Exh. No. CME-1T at 22:4-13.

[324] Energy Project Initial Brief at 3; *See* Kouchi, Exh. No. RK-1T at 9:1-4. These figures refer only to customers who are at 150 percent or less of the federal poverty threshold, the qualifying criterion for the Company's low-income programs. The percentages of low-income customers at 200 percent of the federal poverty level, a threshold used by some utility companies, range even higher from 31 to 49 percent. *Id.* at 9:10-15.

surface of the true low income population, the majority of whom will bear the full brunt of a considerable basic charge increase."[325]

215 Mr. Eberdt also testifies that "we just don't have a good handle on the usage characteristics of PacifiCorp's low-income customers," due to conflicting usage data from the Company's proxy group (LIBA and LIHEAP participants) and the Company's residential use survey completed last year.[326] Accordingly, he recommends rejecting Staff's proposal and requiring the Company to conduct another study that better identifies low-income customers and their usage characteristics.[327] Mr. Eberdt acknowledges that this recommendation is the same as the outcome in the Company's previous general rate case, but argues that the usage study was not done well enough.

216 *Commission Determination:* 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.

217 Staff's similar proposal to raise the basic charge significantly from the current level is tied to its other major rate design recommendation, which is to move Pacific Power's residential rates from a two-block to a three-block inverted rate structure. Such rate restructuring might promote conservation to a degree that offsets the incentive to use more electricity that may be caused by a high basic charge but we are not convinced on the record in this case that this is so. Mr. Twitchell, for Staff, performed some analysis of this question as reflected in his testimony in some detail.[328] He cautions, however, that his results "are only rough projections." He testifies that "there are a number of other factors that will affect the total reduction in electricity usage. Staff's

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[325] Energy Project Initial Brief at 3.

[326] Eberdt, Exh. No. CME-9T at 13:12-14:5.

[327] *Id.* at 14:7-15:3.

[328] Twitchell, Exh. No. JBT-1T at 30:12-33:11.

projection should be interpreted as an upper-bound estimate of the reduced usage that may occur."[329]

218 The Commission supports generally the concept of adding a third block to residential rates because it sends a price signal that promotes conservation and distributed generation. Yet we hesitate to implement a third block with a low basic charge in this case because, as Staff acknowledges, "Staff's core proposals (the increased basic charge and the third rate block) are mutually dependent."[330] No party provides analysis of the customer bill impact and company revenue impact of implementing a third block with a low basic charge. Without this analysis in the record, we are unwilling to implement a third block with a low basic charge in this case.

219 While we hope to see in the Company's next case a proposal from Pacific Power, Staff, or other parties for a third block rate that is not tied to a higher basic charge for residential customers,[331] we remain concerned about the impact of adding a third block on low-income customers. We acknowledge and commend the parties for presenting data and some analysis of the issue in the record of this case. However, the evidence does not dispel the concerns raised by the Energy Project that the rate design proposals by the Company and Staff will disproportionately impact the customers least able to afford high basic charges and high third-block usage rates. We expect the Company and others to continue developing data and undertaking analyses of low-income customer usage patterns in Pacific Power's service territory. These can inform thoughtful consideration in testimony in the Company's next general rate case concerning the price signals a third block rate design will likely have on such customers.

220 Several parties touch on decoupling, recognizing it as the Commission's preferred approach to address the various goals the Company and Staff residential rate design proposals are meant to address. The Commission's long history with decoupling dates back to 1991, when the Commission first approved decoupling for PSE's

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[329] *Id.* at 33:12-15.

[330] Staff Initial Brief ¶ 130.

[331] We note the Commission's approval of such a rate design for Avista and the Commission's recent approval of a settlement adding a third block to PSE's residential rates. *See WUTC v. Avista Corp.,* Docket UE-140188 and UG-140189, Order 05 (November 25, 2014); *WUTC v. Puget Sound Energy, Inc.,* Docket UE-141368, Order 03 (January 29, 2015).

predecessor electric company, Puget Sound Power & Light Company.[332] In 2005, the Commission conducted a rulemaking inquiry into the subject of decoupling. After taking stakeholder comments and conducting a workshop, the Commission determined that "the wide variety of alternative approaches to decoupling make it more efficient to address these issues in the context of specific utility proposals included in general rate case filings rather than through a generic rulemaking."[333]

221 Following this, the Commission considered several decoupling proposals, implementing some and rejecting others.[334] In its 2010 Decoupling Policy Statement, the Commission expressed support for full decoupling and provided utilities and other parties with guidance on the elements that a full decoupling proposal should include.[335] Essential to the policy was recognition that the mechanism should aid the company when revenue per customer decreases and aid the customer when revenue per customer increases. The Commission stated that it believed that "a properly constructed full decoupling mechanism that is intended, between general rate cases, to balance out both lost and found margin from any source can be a tool that benefits

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[332] *WUTC v. Puget Sound Power & Light Company*, Docket UE-901183-T and *In the Matter of the Petition of Puget Sound Power & Light Company for an Order Approving a Periodic Rate Adjustment Mechanism and Related Accounting,* Docket UE-901184-P, Third Supp. Order (April 1, 1991. This program was referred to as Periodic Rate Adjustment Mechanism or PRAM. The Commission monitored the program closely and, in 1993, determined it was achieving its primary goal of removing disincentives to the Company's acquisition of energy efficiency. *See Petition of Puget Sound Power & Light Company for an Order Regarding the Accounting Treatment of Residential Exchange Credits, Docket UE-920433, WUTC v. Puget Sound Power & Light Company*, Docket UE-920499 and *WUTC v. Puget Sound Power & Light Company*, Docket UE-921262 (consolidated), Eleventh Supp. Order at 10 (September 21, 1993). However, in 1995, at the Company's request, the Commission approved discontinuance of the PRAM. *See WUTC v. Puget Sound Power & Light Co.*, *Third Supp. Order Approving Stipulations; Rejecting Tariff Filing; Authorizing Refiling*, Docket UE-950618, at 6 (Sept. 21, 1995).

[333] Rulemaking to Review Natural Gas Decoupling, Docket UG-050369, Notice of Withdrawal of Rulemaking (October 17, 2005).

[334] *See* W*UTC v. PacifiCorp*, Docket UE-050684, Order 04, ¶¶ 108-110 (April 17, 2006); *In re Petition of Avista Corp. for an Order Authorizing Implementation of a Natural Gas Decoupling Mechanism and to Record Accounting Entries Associated with the Mechanism,* Docket UG-060518, Order 04 (February 1, 2007); *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-060266 & UG-060267, Order 08, ¶¶ 53-69 (January 5, 2007); and W*UTC v. Cascade Natural Gas Corp.*, Docket UG-060256, Order 05, ¶¶ 67-85 (January 12, 2007).

[335] *See In re WUTC Investigation into Energy Conservation Incentives,* Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, including Decoupling, To Encourage Utilities to Meet or Exceed Their Conservation Targets at (Nov. 4, 2010) (Decoupling Policy Statement).

both the company and its ratepayers."[336] By "decoupling" sales from revenues, a utility should no longer be encouraged to sell more energy, and conserve less, in order to earn more profit. Ending this so-called "throughput incentive" is the essence of a full decoupling mechanism.[337]

222 We approved full decoupling for PSE in 2013[338] and for Avista in 2014.[339] We invite such a proposal from Pacific Power and other parties in the Company's next general rate case. We encourage Pacific Power to engage in meaningful discussion with Staff, Public Counsel, and other interested stakeholders and to develop a proposal.

b) Non-Residential Rates

223 The Company proposes several non-controversial changes to its non-residential rate design. For Schedule 48T and 48-T Dedicated Facilities, the Company proposes larger increases to demand charges than other portions of rates.[340] Neither Boise White Paper nor Staff oppose the Company's proposal for these schedules. For general service, agricultural pumping, and street lighting schedules, the Company proposes allocating more of the increase to demand rates in order to move cost components closer to cost of service.

224 Walmart proposes a substantial increase to demand charges and a substantial decrease in energy charges for Large General Service Schedule 36. Walmart argues that "Pacific Power's current and proposed Schedule 36 charges are not reflective of the underlying cost of service and are disproportionately weighted towards collection of energy-related costs and, as a result, under collect demand-related costs."[341] In

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[336] Decoupling Policy Statement ¶ 27.

[337] *See* Regulatory Assistance Project, *Revenue Regulation and Decoupling: A Guide to Theory and Application.*

[338] *In the Matter of the Petition of Puget Sound Energy, Inc. and NW Energy Coalition For an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and to Record Accounting Entries Associated with the Mechanisms,* Dockets UE-121697 and UG-121705, Order 06 (June 25, 2013).

[339] WUTC v. Avista Corporation, Dockets UE-140188 and UG-140189, Order 05 (November 25, 2014).

[340] Steward, Exh. No. JRS-1T at 29.

[341] Walmart Initial Brief ¶ 11 (citing *See* Chriss, Exh. No. SWC-1T at 11:10-18).

addition, Walmart argues Pacific Power's proposed charges for Schedule 36 inappropriately shift transmission and generation demand cost responsibility from lower load factor customers to higher load factor customers resulting in a misallocation of cost responsibility because higher load factor customers will overpay for the demand-related transmission and generation costs.[342] Walmart proposes four specific changes to Schedule 36 charges relative to the Company's tariff unbundling proposal:[343]

- Set the unbundled generation (non-NPC) demand charge and transmission demand charge at 50 percent of their cost-based levels.
- Accept the energy charge block structure and price ratio as proposed by Pacific Power.
- Reduce the generation (non-NPC) energy charge revenue requirement by an amount equal to the demand charge revenue requirement increase.
- Reflect any reductions in Schedule 36 revenue requirement from Pacific Power's filed proposal by reducing the generation (non-NPC) energy charges and transmission energy charges.[344]

225 On rebuttal, the Company provides a revised proposal for Schedule 36 that moves towards, but does not match, Walmart's proposal. Ms. Steward testifies that:

> The Company agrees in part with Walmart's proposed rate design, however, the Company is proposing a more gradual movement in increasing the demand charge for Schedule 36 in light of bill impacts. Specifically, the Company proposes a movement that is half way between a rebuttal rate calculated the same as the original filing of $3.49 or approximately 40 percent of total generation demand and Walmart's 50 percent generation demand proposal or $4.38. The proposed rate of $3.94 is approximately 45 percent of total generation

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[342] *Id.* ¶ 12.

[343] We discuss and reject the Company's unbundling proposal in the next section of this Order.

[344] Id. ¶ 13 (citing Chriss, Exh. No. SWC-1T at 15:18-17:5).

> demand costs. The transmission demand rate is calculated using the same approach as applied above but for transmission demand.[345]

226 *Commission Determination:* The principle of gradualism is an important consideration in making changes in rate design proposed by a commercial customer that will have a bill impact for the entire class of customers served under a given rate schedule. We accept Pacific Power's proposed changes to non-residential rate design, including the Company's revised proposal, on rebuttal, for Schedule 36 that is generally consistent with what Walmart recommends but implemented more gradually.

c) Unbundled Rates

227 Pacific Power proposes to unbundle rates in its tariffs by service function. The purpose, according to Ms. Steward is to make the costs associated with the different utility functions shown in the COSS (*i.e.,* generation, transmission, and distribution) more readily transparent in rates.[346] None of the parties expressly object to the Company providing a more granular description of costs in its tariffs. Walmart, moreover, supports the idea and encourages the Company to show unbundled rates on its bills as well.[347] Ms. Steward testifies that:

> The Company supports increased transparency in rates and accordingly is willing to work with parties to add greater cost transparency on bills for non-residential customers through unbundled rates. For residential customer bills, it will be important to incorporate customer education prior to making changes on the bills in order to minimize customer confusion. As such, any roll out in reflecting unbundled rates on bills will need to be staggered between residential and non-residential customer bills.[348]

228 Describing the Company's concept of unbundling, Ms. Steward testifies that the Company includes the costs for customer services, billing, and meter reading from the

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[345] Steward, Exh. No. JRS-13T at 49:19-50:3.

[346] Steward, Exh. No. JRS-1T at 2:13-16.

[347] Walmart Initial Brief ¶ 10.

[348] Steward, Exh. No. JRS-13T at 20:10-16.

cost of service study in the Distribution category.[349] She says also that "[t]he type of rate component used—basic charge, demand charge, energy charge—depends on the type of functionalized cost and whether the costs are fixed or variable."[350] She explains the implications of this, from the Company's perspective, in some detail, as follows:

> Generation is comprised of both fixed (capacity or demand) and variable (energy) costs. As previously discussed, the cost of service study classifies costs between demand and energy using the west control area SDLF. Accordingly, the Company proposes to recover these costs through both energy and demand rates. The variable or net power costs are recovered through energy rates for all rate schedules, which is consistent with cost causation. While cost causation principles would support recovery of generation fixed costs through demand rates, not all customers currently have the metering capability for demand charges, or three-part rates (i.e., basic charges, demand charges and energy charges). For these customers, most fixed costs are currently recovered through energy rates. For the customers that currently do have three-part rates, current demand charges recover only a portion of the fixed generation costs. As discussed below, the Company is proposing larger increases to demand charges to better reflect cost causation; however, to avoid adverse impacts to low load factor customers, in this case the remainder of the allocated generation fixed costs continue to be recovered through energy charges.
> Transmission costs are associated with the bulk transmission system that brings power from the generation source to the load centers. Transmission is also comprised of fixed cost and variable costs. It has been the Commission's accepted practice to use the same classification methodology as used for generation to determine demand- and energy-related costs in the Transmission function in the cost of service study. Therefore, the Company proposes to recover these costs through both demand and energy rates for this case in a similar manner as described above for generation costs.

[349] Steward, Exh. No. JRS-1T at 15:23-16:2.

[350] *Id*. at 16:12-14.

> 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). For rate schedules that do not have three-part rates (where demand meters are not available for load size measurements), as described later the Company designed rates in this case to recover half of these costs through the basic charge and half through energy rates. For all other schedules, the Company proposes to recover these costs through the basic charges and load size charges.

229 *Commission Determination:* The Company does not make entirely clear why it is proposing unbundling rates in its tariffs along the lines described, but until the proposal is more fully vetted we are concerned that this is a first step in a direction the Commission may not wish to go. We find interesting, for example, that the Company actually proposes to bundle the costs normally categorized as "direct customer costs" (*i.e.,* customer services, billing, and meter reading) in the cost of service study, in the "Distribution" category. This is consistent with the Company's proposal in this case to increase dramatically the basic charge to residential customers by adding distribution costs to the basic charge which ordinarily includes only direct customer costs. We earlier reject in this Order the Company's proposed increase in the basic charge. Were we to accept the Company's unbundling proposal, which in this instance amounts instead to a bundling proposal, this might signal acceptance of the idea that distribution costs are properly recovered in a basic charge. Looking at other evidence sponsored by the Company, this could lead to proposals to increase the residential basic charge to $28 and then to $47 so as to recover all fixed costs of distribution to residential customers through the basic charges. As we discuss above, a well-developed decoupling mechanism will address any issues the Company may have with respect to recovery of its fixed distribution costs.

230 Ms. Steward's discussion of fixed and variable costs in connection with generation and transmission presents similar concerns. It appears that in Pacific Power's view the only barriers to straight fixed-variable rate design are metering capabilities and three-part rates. Were we to accept the Company's unbundling proposal, this might be taken as a signal that the Commission is prepared to move in the direction of such a rate design for all classes of customers. We are not.

231 Proposals such as these are more effectively considered in separate proceedings or in industry-wide discussions in workshops. We reject the Company's proposal to unbundle rates in its tariffs in the fashion described in Ms. Steward's testimony.

d) *Tariff Rule 11D and Tariff Schedule 300*

232 Pacific Power initially proposed to modify Section B of Rule 11D, *Field Visit Charge*, by adding language providing that the Company may assess such a charge if an action by a customer during a field visit prevents the Pacific Power employee from disconnecting or reconnecting the customer's meter.[351] In addition, Ms. Coughlin's direct testimony relates that the Company proposed to add language to Rule 11D to specify that individual customers are responsible for paying the collection agency costs associated with the collection of their unpaid debt, rather than having these costs recovered in rates.

233 *The* Company also proposes that a new charge, Non-Radio-Frequency Meter Accommodation, be added to Schedule 300. This new charge coincides with the proposed addition of non-radio-frequency meter accommodation language proposed for Rule 8. The "accommodation" is for customers who wish to have a meter that does not emit radio signals because they have concerns that such meters may affect their health. Pacific Power proposes to charge a one-time $240 fee, ostensibly to cover installation and removal costs, and $20 per month to have a field employee read the meter.

234 In addition, the Company proposes to modify the amounts for the following charges "to more closely align with the Company's costs to perform the work:"[352]

- Connection Charge
- Reconnection Charge
- Unauthorized Reconnection/Tampering Charge
- Facilities Charge

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[351] Coughlin, Exh. No. BAC-1T at 4:6-26.

[352] *Id.* at 11:16-21.

235 Ms. Steward testified for the Company on rebuttal that:

> In response to concerns raised by the parties, the Company is willing to withdraw its proposal for the Collection Agency to charge the customer as reflected in the changes proposed for Rule 11D, its proposal for changes to the Field Visit Charge language in Rule 11D, and its proposal to increase the Connection Charge and Reconnection Charge. In doing so, an adjustment of $83,324 to increase revenue requirement is being made. [353]

236 The Company continues to support the following proposed charges in Schedule 300:[354]

Proposed Changes to Schedule 300

Schedule 300 (Note 1)	Existing	Proposed
Rule 8: Non-Radio Frequency Meter Charge (new charge)[355]	N/A	$240 (+ $20/ month)
Tampering/Unauthorized Reconnection Charge[356]	$75	$110
Line Extension Facilities Charge (company's exp.) [357]	1.67%	1.20%
Line Extension Facilities Charge (customer's exp.)	0.67%	0.60%
Transmission Facilities Charge (company's exp.)	0%	0.90%
Transmission Facilities Charge (customer's exp.)	0%	0.30%

(Note: Facilities charges are percentages of installed costs per month.)

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[353] Steward, Exh. No. 13T at 51:8-13. We note that this is the actual decrease in *pro forma* revenue, which must be adjusted by applying a conversion factor to arrive at the revenue requirement impact, $87,440. *Compare* Siores, Exh. No. 10T at 3 (Table showing adjustments to revenue requirement indicates increases of $87,440 for withdrawal of proposed Schedule 300 changes and $44,138 for withdrawal of Collection Agency Fees).

[354] Steward, Exh. No. JRS 13-T at 52:9-10. Ms. Steward also identifies the Company's proposed change in the description of the "Returned Check Charge", designating it instead as the "Returned Payment Charge" to be consistent with an earlier change in Rule 10, *Billing*.

[355] Coughlin, Exh. No. BAC-1T at 3:2-9.

[356] *Id.* at 17:12-23, 18:1-3.

[357] *Id.* at 18:12-19:19.

Staff witness Roger Kouchi and Public Counsel witness Stefanie Johnson provided detailed testimony contesting the Company's proposed increases to connection and reconnection charges and changes to Rule 11D that the Company withdrew. Although they do not address specifically the proposed new charge and fee modifications in Table 6, both witnesses recommend that the Commission reject the entire Adjustment 3.8 associated with Schedule 300 because Pacific Power failed to provide a detailed assessment of how these increases would impact low-income customers.[358]

237 *Commission Determination:* Pacific Power used the same method to calculate the unauthorized reconnection / tampering charge as it did to calculate the reconnection / connection charges that it withdrew. Moreover, the magnitude of the proposed change, a nearly 50 percent increase, is similarly significant. If approved, the proposed fee would be the highest in any of PacifiCorp's service territories.[359] We are concerned, too, that Pacific Power failed to provide an assessment of how this fee increase would impact low-income customers. Thus, we reject the Company's proposed increase to the unauthorized reconnection / tampering charge for these reasons.

238 We also reject Pacific Power's proposed reduction to the distribution facilities charge and new facilities charge for transmission facilities. These charges are based on financial models, but Ms. Coughlin's testimony fails to provide adequate support for the cost assumptions used.[360] Ms. Coughlin's calculations, for example, include a combined Federal and State Income rate, despite the fact that Washington does not have state income tax.[361] The record does not include sufficient evidence to support approval of the proposed change in the distribution facilities charge or the new transmission facilities charge.

239 Although it is a close call, we will accept, for purposes of this case, the proposed new fee for a Non-Radio Frequency Meter Charge. We allow the fees principally because they are linked to a new service that some customers may wish to have available. Ms.

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[358] Kouchi, Exh. No. RK-1T, at 28:6, Johnson, Exh. No. SAJ-1T at 12:7-9.

[359] The current unauthorized reconnection / tampering charge is $75 in all of the Company's service areas.

[360] Coughlin, Exh. No. BAC-1T at 18:12-23.

[361] Coughlin, Exh. No. BAC-5.

Coughlin's testimony, however, falls short of demonstrating to our full satisfaction that the proposed fees are reasonable. It appears from her testimony that Company personnel will not perform this work efficiently.[362] In addition, the proposed fee does not compare favorably with significantly lower fees for the same service in other jurisdictions.[363] The bases for these fees warrant further investigation and we expect to see a more fully developed record in the Company's next general rate case. We also expect our Staff to investigate fully the bases and support for this charge.

K. Low-Income Bill Assistance (LIBA)

240 *Pacific* Power's low-income customers continue to face difficult choices as they balance their needs for goods and services against their financial resources. Facing these issues in Pacific Power's 2011/2012 GRC, the Commission approved a settlement that included a five-year plan addressing low-income bill assistance.[364] The plan includes four key elements:

- As a cost-cutting measure, a percentage of the Company's LIBA recipients will be certified every other year, as opposed to annually.
- The program will provide assistance to additional recipients.
- The LIBA eligibility certification fee paid to the community action agencies who administer LIBA will be incrementally increased.
- Funding for benefits received by LIBA participants will be increased to twice the amount of any rate increase authorized by the Commission for Pacific Power.[365]

241 *In* this case, Pacific Power proposed specific changes that are consistent with the five-year plan and are supported by the Energy Project.[366]

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[362] TR. 515:8-12.

[363] TR. 505:6-7.

[364] *See WUTC v. Pacific Power*, Docket UE-111190, Order 07 ¶¶ 17-18 and 40-44 (March 30, 2012).

[365] Eberdt, Exh. No. CME-1T at 3; 16-23.

[366] Energy Project Initial Brief at 2; Eberdt, Exh. No. CME-1T at 4:13-5:2.

242 *Commission Determination:* While the issue of low-income bill assistance is not contested in this proceeding, we call it out for discussion and expressly approve the Company's proposal in this case because the matter is critically important and deserves close attention on a continuing basis. As we did in approving the five-year low-income bill assistance program in 2012, we again commend the Company and the other parties for their proactive endeavors and cooperative behavior in increasing funding to assist those most in need. The Commission's observation in its 2012 order bears repeating:

> While many customers are adversely affected by an increase in their electricity rates, we recognize that the customers eligible for the LIBA program are the most dramatically affected by a rate increase and are the least capable of absorbing any rate increase in their monthly income. Accordingly, changes to the LIBA Program that reduce the administrative burden of annual certification and increase benefits should provide welcome respite to participating customers. Conversely, the increase to the Schedule 91 residential surcharge, eight cents per month, imposes a minimal burden on the customers funding the program.[367]

We encourage continued efforts by the Company, Staff, the Energy Project, and others who recognize the importance of ensuring that low-income customers have access to the vital services Pacific Power provides, to find innovative means to provide it.

L. Regulatory Assets and Liabilities (Deferral Accounts)

1. Merwin Fish Collector (Docket UE-140617)

243 The Commission rejected Pacific Power's request for recovery of costs associated with the Merwin Fish Collector Project (Merwin Project) in Docket UE-130043 because it was not expected to be in service and, hence, used and useful, until at least February 2014.[368] The Commission also found that Pacific Power failed to present

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[367] *WUTC v. Pacific Power*, Docket UE-111190, Order 07 ¶ 42 (March 30, 2012).

[368] Docket UE-130043, Order 05 ¶¶ 200, 203.

evidence that the costs of constructing the project met the known and measurable standard.[369]

244 The Merwin Project was placed in service on March 28, 2014, just over one month before Pacific Power filed this case.[370] As discussed previously, the Company proposes to include the project in rate base as a post-test period major plant addition and the Commission approves that treatment. Just as in the case of any other plant addition found prudent and otherwise appropriate for inclusion in rate base, the Company will earn a return of its investment through depreciation expense and a return on its investment as of the effective date of new rates.

245 *Unlike* other *pro forma* additions to rate base, however, Pacific Power preserved its right to request special treatment by petitioning the Commission on April 14, 2014, in Docket UE-140617 to allow either recovery of costs through a separate tariff rider, or an accounting petition to defer those costs. The Commission rejected the tariff rider but granted the accounting petition for a deferral and consolidated Docket UE-140617 into Docket UE-140762.[371] In the context of this case, the Company proposes to recover the return of, and return on, the Merwin plant beginning as of the date of its deferral petition.[372] That is, the Company asks for both depreciation expense and return on rate base as if the Merwin plant had been approved for inclusion in rate base as of the date of its deferral accounting petition. Pacific Power also requests recovery of O&M costs associated with the Merwin Project from the date of its accounting petition. The impact of the Company's proposal on revenue requirement is $1,875,489.[373]

246 *Staff* proposes the Commission allow the Company to recover the O&M expense and depreciation expense (*i.e.,* return of investment) included in the deferral but exclude

[369] *Id.* ¶ 205.

[370] Siores, Exh. No. NCS-10T 24:9-12.

[371] *WUTC v. Pacific Power & Light Co.,* Docket UE-140762, Order 03 (Order 01 of Docket UE-140617) (May 29, 2014).

[372] The Commission's approval of Pacific Power's deferral petition establishes an exception to the matching principle and the Company, when seeking recovery, thus avoids the prohibition against retroactive ratemaking for the costs authorized for deferral treatment.

[373] Siores, Exh. No. NCS-14, at 5.

pre-tax return on rate base (*i.e.,* return of investment).[374] Staff argues that its recommendation "balances competing policy concerns" by providing shareholders with recovery of depreciation expense and O&M expense incurred during the pendency of this rate proceeding (*i.e.,* between rate effective dates) while not allowing the Company's to recover the return on its investment for the 13 months preceding the date the asset is authorized to be included in rate base. This removes the Company's primary incentive for frequent accounting petitions that effectively add plant to rate base between rate cases.[375]

247 Boise White Paper opposes allowing any of the Merwin Project deferral costs for the same reason Staff proposes disallowing the return on equity component. Mr. Mullins testifies that deferral requests such as this one raise serious issues of equity and fairness. In particular, Mr. Mullins testifies that:

> Customers do not control the timing of rate cases, nor do they have the information or the resources to file petitions requesting deferred accounting of *benefits* the Company receives between rate cases. Rather, customers rely on the regulatory compact and the oversight of the Commission's rate case process to capture and balance both the costs and the benefits the Company realizes between rate cases. It would be unfair to allow PacifiCorp to shift responsibility for all of its expenses to customers through deferred accounting, while allowing the Company to enjoy the benefits it receives until such a time as it chooses to file a rate case.[376]

Boise White Paper argues the Company's request for special treatment of the Merwin Project "is simply unnecessary and harmful to customers, given the

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[374] Ball, Exh. No. JLB-1T at 25:13-19.

[375] Staff Initial Brief ¶ 145. Mr. Ball testifies that "[t]he Commission has previously expressed concern with inter-period adjustments to rate base and Staff shares those concerns." Ball, Exh. No. JLB-1T at 27:13-14. The Commission's primary concern is that granting such adjustments provides an incentive for frequent deferral accounting petitions.

[376] Mullins, Exh. BGM-1CTr at 70:21-71:2 (quoting ICNU Comments on Petition of PacifiCorp, Docket No. UE-140617 at 4 (May 27, 2014)).

return and depreciation treatment already available to the Company in the normal rate base mechanism."[377]

248 Public Counsel also opposes approval of any part of Pacific Power's request to recover deferred Merwin Project costs, essentially for the same reasons as Boise White Paper. Public Counsel argues that cost recovery between rate cases "violates the general restriction on single-issue ratemaking."[378] He argues that the Company has not established a basis for an exception to this doctrine and that it is neither fair nor reasonable to single out the Merwin Project for special treatment between rate cases. It is enough, in Public Counsel's view, to include the Merwin Project plant in rate base just like any other *pro forma* major plant addition, which allows for "the reasonable and sufficient recovery of Merwin Project costs."[379]

249 *Commission Determination:* While not unique, the Merwin Project is of a type that is unusual. The installation of this fish collector was necessary for the Company to secure a new Federal Energy Regulatory Commission (FERC) license, which will allow the Company to continue to operate the Lewis River dams for an additional 50 years.[380] The project's design was dictated and approved by federal regulators.[381] Because of this project, albeit not revenue producing itself, customers will continue to benefit from the Company's emission-free, low-cost hydropower generation.[382]

250 Staff refers us to a somewhat similar situation that confronted Avista, leading the company to file a petition for an accounting order to defer costs related to the improvement of dissolved oxygen levels in Lake Spokane.[383] This project was also part of a FERC licensing process and also involved the Washington Department of Ecology. Avista recorded its costs for the project as Construction Work in Progress. It intended to capitalize the costs after construction of a facility that was anticipated to be required as part of an attainment plan. Once a non-facility based plan was

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[377] Boise White Paper Initial Brief ¶ 105.

[378] Public Counsel Initial Brief ¶ 79.

[379] *Id.* ¶ 80.

[380] Docket UE-130043, Order 05 ¶ 196.

[381] *Id.*

[382] *Id.*

[383] Petition of Avista Corporation, Docket UE-131576, Order 01 ¶ 1.

approved, however, Avista requested deferral accounting treatment for its costs with the intention to seek a determination of eligibility for recovery "in their next general rate case or in a separate filing."[384] Avista did not seek and the Commission did not authorize the accrual of interest (*i.e.,* return on investment) on the Washington share of the deferrals.[385]

251 While a close call, the approach taken in the Avista case provides guidance and influences us to accept Staff's recommendation with respect to the Merwin Project deferral. We take seriously the concerns Staff, Public Counsel, and Boise White Paper raise with respect to the importance of discouraging companies from filing accounting petitions as a means to secure between-rate-case cost recovery for plant additions. We are nearly persuaded to reject Pacific Power's request for recovery of any of these costs and to treat the Merwin Project just as any other post test period *pro forma* adjustment to rate base. We emphasize, then, that the treatment we allow in this instance is exceptional and turns on the unusual nature of the project involved. We authorize recovery of the Merwin Project's deferred O&M costs and depreciation from the date of the Company's deferral petition through the day preceding the rate effective date of Pacific Power's compliance filing in Docket UE-140762. This deferral will allow the Company to recover $530,000 in such costs, but exclude any deferred interest. The recovery will be through Pacific Power's Tariff Schedule 92. Pacific Power is authorized to include the Merwin Project in rate base and will recover return on, in addition to return of, its investment prospectively, beginning on the rate effective date.

2. Colstrip Outage (Docket UE-131384)

252 Pacific Power filed a petition for an accounting order on July 26, 2013, in Docket UE-131384, requesting an order authorizing the Company to defer from the date of the petition forward its costs for repair and replacement purchase power for an outage at the 740-megawatt unit 4 of the Colstrip generating plant located in Colstrip, Montana.[386] The petition followed a major plant failure on July 1, 2013, resulting in material damage to the unit. The Company estimated the costs to repair the plant

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[384] *Id.* ¶ 5.

[385] *Id.*

[386] Petition for an Accounting Order, Docket UE-131384, (July 23, 2013) at ¶ 1.

would range between $3 million to $4 million and was expected to take at least six months to complete.[387]

253 Although we have found no related discussion in the record, it appears from a comparison of Ms. Siores' direct and rebuttal exhibits that the Company removed the costs of repair from its deferral accounting,[388] leaving only a request to defer replacement power costs. We presume this means the Company now elects to recover the costs of repair as a capital cost in base rates, rather than through a Schedule 92 surcharge addition.

254 The Company estimates that additional power purchases required to replace the lost energy normally obtained from the damaged unit range from $9 million to $12 million over the anticipated term of the outage.[389] The Company requests deferral accounting treatment for the replacement power costs, and for recovery of the deferred costs in base rates.

255 On June, 24, 2014, without acting on the petition, the Commission consolidated Docket UE-131384 into this general rate case in Docket UE-140762.[390] In the context of the consolidated cases the Commission must determine whether to grant the petition and, if so, whether to allow recovery of the deferred costs.

256 The Company's only mention of the deferral in its direct testimony is that its initial filing in UE-131384 is consistent with Staff testimony in Docket UE-080220. It was in that proceeding that Staff recommended the company file an accounting petition to request deferral and possible recovery of excess costs resulting from extended forced outages.[391]

257 *Staff's* witness, Ms. Erdahl, does not oppose the proposed deferral and recovery of both the repair and the replacement power costs, but recommends that they be

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[387] *Id*. ¶ 4.

[388] Compare Exh. No. NCS-9 at 1-3 to NCS-14 1-2.

[389] *Id*. ¶ 5.

[390] Docket UE-140672, Order 01 (June 24, 2014).

[391] Dalley, Exh. No. RBD-1T at 7:5-11.

recovered without recognition of an interest component.[392] Additionally, under Staff's approach, the Company's recovery of the deferred costs would be as an element of the revenue requirement model, embedded in base rates, not as a component of the Company's proposed Schedule 92.[393]

258 The Company opposes Staff's recommendation that no interest be allowed if the petition is approved and deferral accounting is authorized. Ms. Siores testifies that removal of interest expense does not account for the time value of money which means the financing costs on any deferred amounts will not be recovered.[394] Ms. Siores does not address Ms. Erdahl's objection that the Company's approach enables earning interest on revenue-sensitive taxes.

259 *In* response to Staff's position that a separate tariff not be used to collect the deferral, Ms. Siores maintains that once the amounts are fully amortized, collection under the separate tariff rider will cease, whereas if the deferrals are included in the permanent rates the Company will continue to collect the rates until the next rate case.[395]

260 Mr. Mullins opposes deferral and recovery of any Colstrip cost because, in his opinion, the outage was not an extraordinary event.[396] Mr. Mullins also claims that the Company has failed to provide any updated estimated costs incurred, a point Ms. Siores rebuts in her testimony. According to Ms. Siores, the Company provided updates in its initial filing, showing actual costs, in her exhibit NCS-9.[397]

261 Mr. Mullins testifies that it is the Company's failure to gain approval of a properly designed PCAM, which the Commission has more than once invited it to file, that now should prevent it from deferring and recovering the costs of replacement power.[398] Mr. Mullins argues in addition that the Company should not be allowed to defer and recover its costs because, in his view, the Colstrip failure is directly

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[392] Erdahl, Exh. No. BAE-1T at 11:10-16.

[393] *Id.* at 11:1-7.

[394] Siores, Exh. No. NCS-10T at 21:16-19.

[395] *Id.* at 21:20-22:2.

[396] Mullins, Exh. No. BGM-1CT at 62:11-66:18.

[397] Siores, Exh. No. NCS-10T at 22:7-11.

[398] Mullins, Exh. No. BGM-1T at 62:12-63:5.

attributable to the plant's operator as a result of faulty repair work done at the time of the prior outage. Mr. Mullins contends the costs attributable to this latest failure are more properly recovered from the operator and not Washington rate payers.[399]

262 Mr. Ralston, in rebuttal testimony for Pacific Power, disputes Boise White Paper's contention that the Colstrip operator was imprudent. Mr. Ralston testifies that the fact that the root cause scenario could not identify with certainty the cause of the outage, does not support a conclusion that the operator was not at fault.[400] Focusing on the failure report an outside expert prepared for the Company, Mr. Ralston testifies:

> Boise suggests that factual evidence available was not adequate to develop a failure cause and that concrete evidence and a clear indication of failure must be present to show the Company's actions were prudent. However, the failure report was very detailed and used all the information available, including plant logs, relay and alarm data, and physical inspections of the damage by industry expects. Boise discounts the statement by the external root cause investigating team that, "[i]n our opinion, PPL did everything according to standard industry practice such as hiring the OEM (Siemens) to perform the maintenance, performing El Cid testing on the core, operating their unit according to industry practice, (since there was no indication of mis-operation), and protecting the unit with adequate relay protection. Nothing they did or could have done, could have prevented this failure." This statement, along with the rest of the report, demonstrates that the Company acted prudently and took all recommended steps to maintain the equipment as per the OEM recommendations.[401]

Mr. Ralston concludes that: "Boise's claim is speculation unsupported by the expert analysis in the root cause report."[402]

263 *Commission Determination*: We deny Pacific Power's accounting petition. The replacement power costs in question do not qualify as extraordinary costs such as might arguably be candidates for deferral accounting. As recently as Pacific Power's

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[399] *Id.* at 64:16-66:18.

[400] Ralston, Exh. No. DMR-2T at 8:15-17.

[401] *Id.* at 9:1-13.

[402] *Id.* at 10:1-2.

2012/2013 GRC, the Commission made clear its preference for a properly designed PCAM that addresses all of the Company's power costs, not a single element. Order 05 also expresses the Commission's objections to power cost recovery mechanisms that are nothing more than trackers. Pacific Power's deferral request here is nothing more than a single element power cost tracker. As previously discussed, the Commission, through this Order, will require Pacific Power to file tariff sheets implementing a properly designed PCAM along the lines of Staff's proposal in this case. Once in place, this will resolve power cost recovery issues such as those presented in Docket UE-131384.

3. Hydropower Deferral (Docket UE-140094)

264 Pacific Power filed a petition for an accounting order in Docket UE-140094 on January 17, 2014, seeking to defer costs that the Company anticipated it would incur during 2014 due to decreased hydropower production (hydro). Pacific Power requested specifically an order authorizing the Company to defer from the date of its petition forward any increased power costs caused by declines in hydro generation, due to abnormally dry weather conditions. Pacific Power sought deferral of these costs to track and preserve them for later ratemaking treatment.

265 On June, 24, 2014, without acting on the petition, the Commission consolidated Docket UE-140094 into this general rate case.[403] In the context of the consolidated cases the Commission must determine whether to grant the petition and, if so, whether to allow recovery of the deferred costs.

266 Pacific Power's petition states that "significant declines in hydro generation due to abnormally dry weather conditions and low water availability" would cause the Company "to make market purchases and rely on more thermal generation to compensate for the shortfall," expected to be in the range of $15 million. Pacific Power presented no evidence with its petition demonstrating the asserted "significant declines" or their magnitude. Nor did Pacific Power present evidence demonstrating any "abnormally dry weather conditions and low water availability" record during periods leading up to the time of its petition in January 2014. Nor did the Company present evidence, other than its bare assertion, projecting that such claimed conditions would persist through the remainder of 2014 or, indeed, for any period of time.

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[403] Docket UE-140672, Order 01 (June 24, 2014).

267 In this case, Pacific Power seeks not only authority to defer these costs, but also proposes to recover $2.4 million in increased costs the Company claims were caused by lower than forecast hydropower during 2014.[404] When this is compared with the $15 million amount suggested in support of the Company's petition, it appears the anticipated conditions, in fact, did not materialize as anticipated.

268 The only testimony the Company offers on this issue in its direct case is by Mr. Dalley in a single sentence stating: "The hydro deferral request is consistent with Commission precedent in Docket UE-080220."[405] Docket UE-080220, however, was resolved on the basis of a settlement among the parties that by its own terms, as approved by the Commission, does not establish precedent in any sense of the word.[406]

269 The Company did not present testimony demonstrating significant declines in hydro generation during 2014 either in its deferral petition or in its direct case. Mr. Gomez, for Staff, analyzed the Company's hydro generator performance-based in part on the Company's responses to two data requests – one submitted by Public Counsel and one submitted by Staff.[407] According to Staff, "actual hydro generation (January – August 2014)" when combined with the Company's forecast for the "remainder of the proposed deferral period (September- December 2014)," shows hydro generator output within 2.9 percent of the amount placed into rates.[408] This result was better

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[404] Duvall, Exh. No. GND-4T at 62:8-10.

[405] Dalley, Exh. No. RBD-1T at 7:10-11 (citing *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-080220, Order 05 (Oct. 8, 2008) (approving a settlement allowing amortization of a portion of the Company's 2005 hydro deferral).

[406] The Settlement Stipulation, attached to, and made part of, Order 05 provides in Section L.6. that the agreement is entered into "to avoid further expense, inconvenience, uncertainty and delay." This provision continues with the statement that:

> By executing this Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed in arriving at the terms of this Stipulation, *nor shall any Party be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding*."

Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co., Docket UE-080220, Order 05, Attachment ¶ 33 (Oct. 8, 2008) (*emphasis added*).

[407] Gomez, Exh. No. DCG-1CT at 17:6-7 and 10-12.

[408] Staff Initial Brief ¶ 85 (citing Gomez, Exh. No. DCG-1CT at 17:6-10).

than the Company's experience from 2007 to 2013 when the difference between actual hydropower generation and the amount in rates averaged about 9 percent.[409] Mr. Gomez concluded that the Company's hydro performance during the deferral period (2.9 percent as compared with 9.0 percent) was "well within an acceptable range."[410]

270 In Mr. Duvall's rebuttal testimony, the Company updated its analysis of its hydro output, and represents that the difference between actual hydro generation and the amount in rates would be "approximately 7.6 percent" for all of 2014. Staff argues that even accepting this data, "the Company's actual hydro generation still falls within Staff's acceptable range of 9 percent of forecast."[411] In a similar vein, Mr. Mullins testifies that despite early concerns that hydro conditions during 2014 would be below average for the calendar year, "the Northwest experienced higher than average spring precipitation, which has resulted in Northwest hydro conditions that are about normal."[412]

271 Mr. Mullins also testifies that the Commission should reject the Company's deferred accounting proposal because it is one-sided.[413] As he explains it:

> The Company forecasts hydro output in the GRID model based on median generation of a historical period. Accordingly, half of the time hydro generation is expected to be lower than the Company's forecast, and half of the time it is expected to be higher. In this case, the Company is seeking deferred accounting for costs associated with hydro generation that it originally expected to be below the median forecast; yet, the Company has not made similar proposals when hydro generation has been greater than the median.[414]

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[409] *Id.* (citing Gomez, Exh. No. DCG-1CT at 17, see Footnote 28).

[410] Gomez, Exh. No. DCG-1CT at 17:10-11.

[411] Staff Initial Brief ¶ 85.

[412] Mullins, Exh. No. BGM-1CT at 67:5-12.

[413] *Id.* at 67:16.

[414] *Id.* at 67:17-22.

Mr. Mullins cites 2011 and 2012 as examples, observing that "when the spring run-off was well above the median, the Company made no effort to return the savings attributable to the higher than average hydro conditions."[415]

272 Staff, referring to the Company's proposal as a "Hydro Tracker," says that the Company seeks to recover ordinary variability in power costs, shielding itself entirely from the effects of weather, resulting hydro conditions, and changes in fuel costs.[416] Staff argues that the Commission previously has rejected the inclusion of normal hydro variability in power cost adjustment mechanisms. Indeed, as recently as Order 05 in Docket UE-130043 the Commission said:

> PacifiCorp, however, proposes a PCAM that would protect the Company from any risk of under-recovery, even that due to the ordinary variability in power costs due to normal and foreseeable changes in fuel costs, ordinary variance in hydro conditions, normal variations in weather, and so forth. As the Commission previously observed in connection with such a proposal: "This would mark a new and much expanded role for the PCA."[417]

Staff asserts that despite such clear Commission guidance, the Company here seeks identical but narrower relief through its Hydro Tracker.

273 *Commission Determination:* We deny Pacific Power's petition for an accounting order and, consequently, its proposed recovery in rates of any costs it would otherwise be authorized to book as deferred power costs. These costs are in no sense "extraordinary," a criterion that should apply to a cost deferral accounting mechanism at the time requested and at the time any recovery is sought.

274 *As* stated previously, we do not favor narrow, single purpose trackers that use deferral accounting to recover on a dollar-for-dollar basis all variations in wholesale power costs, whether or not such variations are outside of the Company's control. Instead, as the Commission has stated clearly in prior orders, such issues should be examined on the basis of the Company's total portfolio of resources, and include mechanisms to

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[415] *Id.* at 67:22-24.

[416] Staff Initial Brief ¶ 89 (citing Gomez, Exh. No. DCG-1CT at 17:17-20 and at 18:1-3).

[417] Docket UE-130043, Order 05 ¶172.

protect customers as well as promoting the Company's ability to recover such costs in a timely manner.

275 As previously discussed in this Order, we require Pacific Power to file tariff sheets implementing a properly designed PCAM along the lines of Staff's proposal in this case. Once in place, this will resolve power cost recovery issues such as those presented in Docket UE-140094.

4. Depreciation Deferral

276 On December 31, 2013, Pacific Power filed a petition in Docket UE-132350 seeking to defer a reduction in depreciation expense resulting from the difference in depreciation rates that were approved in Docket UE-130052 and the amount of depreciation expense used for setting rates in Docket UE-130043. In Order 01 of UE-132350, the Commission allowed the Company to defer the one-time reduction of depreciation expense of $669,000 until such time as the deferred amount could be refunded through an appropriate adjustment to rates in Pacific Power's subsequent GRC, which is this proceeding. The Company, recognizing the increased deferral balance since the original filing, reflects the total reduction to revenue requirement for the rate year of $877,345.[418]

277 Staff agrees with the refund calculation reflecting the increased balance of the deferral, but Staff disagrees with the use of a separate tariff rider as the mechanism for the refunding the over-collection of depreciation expense. Instead of handling it through Schedule 92 as the Company proposes, Staff proposes to recognize the impact of the credit to customers as a reduction to revenues in the overall revenue requirement model.[419]

278 In response, Ms. Siores testifies that once the deferred amount is fully amortized, the credit under Schedule 92 will cease, whereas if the deferrals are included in permanent rates as Staff suggests, this will not occur until adjusted out of rates in a future rate case. [420]

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[418] Siores, Exh. No. NCS-14 at 3.

[419] Erdahl, Exh. No. BAE-1T at 11:3-8.

[420] Siores, Exh. No. NCS-10T at 22:3-7.

279 *Commission Determination:* The deferral amount is not contested and we approve its recovery as a credit to customers reflected in Schedule 92.

FINDINGS OF FACT

280 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

281 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including electrical and gas companies.

282 (2) Pacific Power is a "public service company" and an "electrical company," as these terms are defined in RCW 80.04.010 and as these terms otherwise are used in Title 80 RCW. Pacific Power is engaged in Washington State in the business of supplying utility services and commodities to the public for compensation.

283 (3) Pacific Power's current rates do not yield sufficient compensation for the electric services it provides in Washington.

284 (4) Pacific Power requires relief with respect to the rates it charges for electric service provided in Washington State so that it can recover its electric service revenue deficiencies.

285 (5) The record supports a capital structure and costs of capital, which together produce an overall rate of return of 7.30 percent, as set forth in the body of this Order in Table 2.

286 (6) The Commission's resolution of the disputed issues in this proceeding, identified in Appendix A to this Order, coupled with its determination that certain uncontested adjustments identified in Appendix B to this Order, and taking into account the Commission's determinations of the consolidated dockets concerning deferrals as shown in Appendix C, are reasonable, results

in our finding that Pacific Power's electric revenue deficiency is $9,568,464, as set forth in detail in Table 3, in the body of this Order.

287 (7) Applying the requirements of the five-year low-income bill assistance program approved in Docket UE-111190 in March 2012 results in appropriate adjustments that enhance support for the Company's programs for low-income customers.

288 (8) The rates, terms, and conditions of service that result from this Order are fair, just, reasonable, and sufficient.

289 (9) The rates, terms, and conditions of service that result from this Order are neither unduly preferential nor discriminatory.

CONCLUSIONS OF LAW

290 Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

291 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings.

292 (2) Pacific Power failed to show that the rates it proposed by tariff revisions filed on May 1, 2014, which were suspended by prior Commission order, are fair, just or reasonable. These as-filed rates accordingly should be rejected.

293 (3) Pacific Power carried its burden to prove that its existing rates for electric service provided in Washington State are insufficient to yield reasonable compensation for the service rendered.

294 (4) Pacific Power requires relief with respect to the rates it charges for electric service provided in Washington State.

295 (5) The Commission must determine the fair, just, reasonable, and sufficient rates to be observed and in force under Pacific Power's tariffs that govern its rates,

terms, and conditions of service for providing electricity to customers in Washington State.

296 (6) The costs of Pacific Power's investments found on the record in this proceeding to have been prudently made and reasonable should be allowed for recovery in rates.

297 (7) Pacific Power should have the opportunity to earn an overall rate of return of 7.30 percent based on the capital structure and costs of capital set forth in the body of this Order.

298 (8) Pacific Power should be authorized and required to make a compliance filing to recover its revenue deficiency of $9,568,464 for electrical service provided to its customers in Washington.

299 (9) The Commission should reject rate design proposals to increase substantially basic charges to residential customers. The Commission should otherwise make adjustments to the Company's cost of service, rate spread, and rate design as discussed in the body of this Order.

300 (10) Pacific Power should be authorized to increase funding for the Company's Low Income Bill Assistance Program as provided by the five-year low-income bill assistance program approved in Docket UE-111190 in March 2012.

301 (11) The rates, terms, and conditions of service that will result from this Order are fair, just, reasonable, and sufficient.

302 (12) The rates, terms, and conditions of service that will result from this Order are neither unduly preferential nor discriminatory.

303 (13) Pacific Power, following additional process, should be required to file tariff sheets to make effective a Power Cost Adjustment Mechanism that is consistent with the Commission's design preferences, including among other things, appropriate dead bands and sharing bands that balance risk between the Company and its customers.

304 (14) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

305 (15) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS THAT:

306 (1) The proposed tariff revisions Pacific Power filed on May 1, 2014, which were suspended by prior Commission order, are rejected.

307 (2) Pacific Power is authorized and required to file tariff sheets that are necessary and sufficient to effectuate the terms of this Order, including determinations of a revenue deficiency of $9,568,464 for electrical service. Pacific Power must file the required tariff sheets at least two full business days prior to their stated effective date, which shall be no sooner than April 1, 2015.

308 (3) Pacific Power is authorized and required to increase funding for the Company's Low Income Bill Assistance Program as provided by the five-year low-income bill assistance program approved in Docket UE-111190 in March 2012.

309 (4) Pacific Power is required to participate in further proceedings in this docket to develop fully, and implement by filing appropriate tariff sheets, a Power Cost Adjustment Mechanism designed to be consistent with guidance the Commission has given in prior orders, as discussed in the body of this Order.

310 (5) The Commission Secretary is authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Final Order.

311 (6) The Commission retains jurisdiction to effectuate the terms of this Final Order.

Dated at Olympia, Washington, and effective March 25, 2015.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chairman

PHILIP B. JONES, Commissioner

ANN E. RENDAHL, Commissioner

NOTICE TO PARTIES: This is a Commission Final Order. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 and WAC 480-07-870.

Commissioner Jones' Separate Statement on Rate Design

312 I concur with the Majority with the end result in rate design, but write separately to express my differences with the tenor and rationale in our rejection of both the Company's and Staff's proposals. At the outset, I wish to reiterate that the burden remains with the Company to develop a just and reasonable rate design, and reflect the traditional regulatory principles of fairness and gradualism when spreading costs among customers. Staff and the stakeholders have an obligation to respond in good faith to the utility's proposals, but ultimately Pacific Power must provide sufficient facts and rationale to justify its proposals.

313 I differ with the Majority, however, in encouraging the Company to put forward a full decoupling proposal as the preferred option. Although it doesn't require Pacific Power to file such a proposal in the next GRC, its critique of the Company and Staff's proposals in this case, and frequent references to our Decoupling Policy Statement and adoption by PSE and Avista, certainly lead one to that conclusion. Essentially, the Majority appears to argue that the other two electric utilities have adopted full electric decoupling, it is working well, hence Pacific Power should do so as well. We appear to have taken on the role of the teacher who disciplines the disobedient child in the back of the classroom who is causing trouble to step forward to the front of the class and join the exemplary students, in other words, by adopting decoupling. I am not an opponent of decoupling, depending on its detailed design and structures, and have supported its adoption by PSE and Avista. Furthermore, I think the Commission can benefit by assessing different regulatory mechanisms to address flat load growth and potential attrition; a one-size-fits-all approach is not necessarily the best approach.

314 Rate design is a complex issue that attempts to do many things simultaneously, such as reflect fairness among customers, cost causation, adjust to changing utility loads and sources of generation, encourage certain public policy preferences, and protect low-income consumers. This is a very challenging and difficult balance to achieve. In my view, most observers have been aware for many years that most rate design structures do not truly reflect the true, actual costs of serving the various rate classes, especially in the balance between fixed (basic charge) and volumetric (per kilowatt-hour) rates. But most Commissions, including the UTC, have chosen to maintain the current rate design structures for the reasons cited above, namely fairness and gradualism. In this case, the Company proposes a significant increase in the residential basic charge, a dramatic shift away from the traditional residential rate design approved by this Commission over the past decade. In short, the Company has not satisfied its burden in this case to provide evidence and rationale supporting the change.

315 At the same time, I commend the Company and the Staff for setting forth comprehensive, detailed proposals on residential rate design here. The utility business model is evolving quickly in response to changes in technology, energy efficiency, and customer-owned generation, although at different speeds among utilities. Moreover, our Legislature (and many other legislatures throughout the country) and other external stakeholders have focused on these issues and have been developing a variety of proposals at the state level. In response, the Commission has been spending a good deal of time and energy studying and developing broad policy recommendations on these issues in responding to questions and concerns from the Legislature.[421] Although I conclude that these two proposals from the Company and Staff are not sufficiently developed and vetted, the Commission has benefited from the exercise of reviewing and assessing these specific proposals. However, it is premature to act at this time and on this record for the following reasons.

First, the Company, at a senior management level, has to favor decoupling as a mechanism to address issues like attrition, lost margins from conservation, or lost revenues from customer-owned generation. Moreover, it has to have a strong belief in decoupling, compared to other mechanisms, in order to succeed in getting the proposal through a contentious, fact-based regulatory process with other stakeholders. With PSE, we engaged in a multi-year "conversation" about decoupling in which the Company attempted at least twice to persuade us to adopt decoupling proposals, and senior management and Board members were actively engaged. Finally, PSE brought forward an acceptable proposal to us that we adopted as a multi-year pilot in the context of a complex settlement agreement. With Avista, we engaged in a similar process that began with a limited decoupling proposal for natural gas, and resulted in full electric and gas decoupling proposals in the context of a settlement agreement.

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[421] *Study of the Potential for Distributed Energy in Washington State,* Docket UE-110667, Report on the Potential for Cost-Effective Distributed Generation in Areas Served by Investor-Owned Utilities in Washington State (October 7, 2011); *In the Matter of Amending and Repealing Rules in WAC 480-108 Relating to Electric Companies-Interconnection With Electric Generators*, Docket UE-112133, Interpretive Statement Concerning Commission Jurisdiction and Regulation of Third-Party Owners of Net Metering Facilities (July 30, 2014).

316 The context is markedly different with Pacific Power, and its parent company Berkshire Hathaway Energy (BHE). The Company is neutral at best on decoupling mechanisms, and doesn't appear to favor them as the proper mechanism to address issues specific to its cost structure and service territory. In our 2010 proceeding that led to the development of the Decoupling Policy Statement, in fact, the Company responded to the Commission's request for comment on potential mechanisms to address lost revenues and recovery of its fixed costs, namely: decoupling, a lost margin adjustment mechanism, straight fixed variable design (including an increase in the basic charge), and an attrition adjustment.

317 Of the mechanisms discussed, Pacific Power was the most supportive of either a lost margin recovery mechanism, straight-fixed variable rate design (increase in basic charge, decrease in volumetric charge), or some type of attrition adjustment.[422] Regarding a decoupling mechanism, it stated it was "neutral" and mentioned the drawbacks of such a proposal without offering much detail. Since that time, we have not engaged with the senior management of Pacific Power on these issues, and they have never expressed a whit of support for decoupling. Certainly, in this case the Company did not advocate at all for a decoupling mechanism; instead, it advocated for an increase in the residential basic charge to $14. Since the burden ultimately remains with the Company to justify its proposals, I remain cautious about trying to either encourage or impose any specific regulatory mechanism, such as decoupling, without further process and deliberation.

318 The specific proposals of the Company and the Staff raise a number of questions that I think need to be answered more fully before moving forward, including but not limited to:

- The Company argues that the residential basic charge should include the fixed costs of the distribution system.[423] This would include the cost of poles, wires, and line transformers – which traditionally have not been included in the basic charge – in addition to metering, service drop, and customer billing costs traditionally included in the basic

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[422] *In re WUTC Investigation into Energy Conservation Incentives,* Docket U-100522, Comments of Pacific Power (July 14, 2010).

[423] Steward, Exh. No. JRS-1T, at 19:1-14, and JRS-13T, at 22, 15-23, and 23, 1-6. She asserts that its estimate of the costs for what the Company defines as "local distribution and retail service costs" to be $28 per month, of which the Company argues about one-half, or $14, should be included in the basic charge.

charge. Other Parties disagree with the inclusion of distribution system costs in the basic charge, and challenge Pacific Power's classification of these costs as "fixed". Hence, I think the inclusion of distribution system costs in the basic charge, and their classification as either "fixed" or "variable" need to be examined further;

- Staff, to its credit, makes an interesting proposal for the addition of a third volumetric block in an inverted rate block design that would start at 1701 kwH per month, at a cost of approximately 12 cents/kwH. This is an intriguing proposal, but needs more vetting. In the context of a proposal to add a third volumetric block, I would like to see further analysis of price elasticity effects, the amount of "fixed costs" (however defined) included in such a third Block, and the impact on low-income customers. Additionally, rate design experts should continue to explore other options than a third block with decoupling, building upon the various scenarios the Company developed for residential rate design in preparation for the current rate case;

- Overall impact on low-income customers: the Energy Project makes some good points on the potential impacts of rate design proposals on low-income customers, and some of the unique characteristics of that population in Pacific Power's service territory. Although Staff rebutted some of these criticisms in its analysis and offered an alternative low-income basic charge of $8.75, I think this analysis needs further refinement. I also encourage the Energy Project to engage fully with Staff and the Company on these issues, and offer specific alternatives in the recognition that changes in residential rate design are likely to occur sooner rather than later.

- The Company makes repeated references to the growing impact caused by more customer-owned generation in its service territory, but admitted that currently only 244 customers are self-generating with net metering. If this appears to be such a "threat" to the Company's revenues and margins, it needs to make a better case of what estimates or projections it is using.

These are just a few of the many questions that must be addressed and answered more fully in the next rate case that the Company prepares for the Commission. I am open to considering any specific mechanism that the Company wishes to propose for residential rate design; or if the Company prefers, propose one "primary" mechanism, and one "alternative" mechanism for the Commission to consider specifically in the next case. But I reiterate that any proposal needs to be properly supported, balanced, and answer some of the questions and concerns noted above.

319 Meanwhile, as stated above, we are engaging with all electric utilities and stakeholders in our ongoing Collaborative on Distributed Generation and plan to hold a workshop on methods for addressing attrition in April. Since our Legislature and many external stakeholders are engaged in these issues, these fora are the ideal way for Pacific Power and other utilities to engage directly with the Commissioners and Staff on both policy and regulatory issues. I encourage the new senior management of Pacific Power to engage constructively in these collaborative discussions, and propose various alternatives for us and other stakeholders to assess before proceeding to another general rate case. I hope we can invite organizations that have been involved in similar issues with other state commissions, such as the Electric Power Research Institute, Regulatory Assistance Project, solar and renewable industry associations, to help inform our discussions on rate design and the impact of conservation and distributed generation on the distribution grid.

320 In sum, I believe there are better ways for the Company to engage in a constructive dialogue with the Commission, our Staff, and the stakeholders, and move this dialogue forward. These are not easy issues to resolve and involve a complex balancing of a wide diversity of economic and public policy interests. I agree with the Majority that neither the Company's or Staff's proposals are ready for adoption in this case, but I do think they have played a useful role in enhancing our understanding. I do not necessarily think that a decoupling mechanism, however structured, is the preferred or default option for the Company at this time, and am open to consider any proposal in a better developed record that builds upon the dialogue in our Collaborative discussions.

PHILIP B. JONES, Commissioner

APPENDIX A - CONTESTED ADJUSTMENTS

COMMISSION DETERMINATIONS

	Adjustment	Net Operating Income	Rate Base	Revenue Requirement
	Actual Results of Operations	**$40,389,777**	**$788,256,374**	**$27,686,124**
3.8	**Schedule 300 Fee Change**	**-**	**-**	**-**
4.3	**Wage & Employee Benefits - *Pro Forma***	**447,635**	**-**	**(722,516)**
4.7	**Insurance Expense**	**1,739,135**	**-**	**(2,807,094)**
4.13	**IHS Global Insight Escalation**	**-**	**-**	**-**
5.1.1	**Net Power Costs- *Pro forma***	**(3,069,123)**	**-**	**4,953,793**
6.2-6.2.2	**Depreciation & Amortization Reserve to December 2013 Balance**	**-**	**-**	**-**
6.3-6.3.2	**Proposed Depreciation Rates-Expense**	**(886,437)**	**(886,437)**	**1,326,329**
6.5	**Retired Assets Depreciation Expense Removal**	**-**	**-**	**-**
7.1	**Interest True-up***	**29,821**	**-**	**(48,133)**
8.4	**Major Plant Additions**	**(429,735)**	**18,429,412**	**2,865,115**
8.10	**Regulatory Asset Amortization**	**(1,950,000)**	**-**	**3,147,446**
8.12-8.12.6	**Adj. December 2013 AMA Plant Balances to December 2013 EOP Balances**	**-**	**-**	**-**
9.1	**Production Factor**	**(629,599)**	**142,456**	**1,033,006**
	Sub-total Contested Adjustments	**$35,641,474**	**$805,941,805**	**$37,434,070**
	Total Adjusted Results[424]	**$53,850,896**	**$818,890,931**	**$9,568,464**

[424] Sum of Appendix A (Sub-total Contested Adjustments) and Appendix B (Sub-total Uncontested Adjustments).

APPENDIX B – UNCONTESTED AJDUSTMENTS

	Adjustment	Net Operating Income	Rate Base	Revenue Requirement
	Actual Results of Operations			
3.1	Temperature Normalization	$(3,700,295)		$5,972,553
3.2	Revenue Normalization	(4, 827,929)		7,792,639
3.3	Effective Price Change	11,066,786		(17,862,619)
3.4	SO2 Emission Allowance Sales	481,474	(249,925)	(806,582)
3.5	Renewable Energy Credit and Renewable Energy Attribute Revenue	(1,464,670)		2,364,087
3.6	Wheeling Revenue	225,696		(364,290)
3.7	Ancillary Revenue	26,682		(43,357)
3.9	Wind Wake Loss Revenue	16,828		(27,161)
4.1	Miscellaneous General Expense	14,374		(23,201)
4.2	Wage & Employee Benefits - Restating	30,933		(49,928)
4.4	Irrigation Load Control Program	3,472		(5,604)
4.5	Remove Non-recurring Entries	(101,034)		163,076
4.6	DSM Revenue and Expense Removal	6,923,690		(11,175,352)
4.8	Advertising Expense	261		(421)
4.9	Memberships & Subscriptions	(973)		1,570
4.10	Uncollectible Expense	(274,576)		443,186
4.11	Legal Expenses	(60,982)		98,430
4.12	Collection Agency Fees	-	-	-
5.1	Net Power Costs - Restating	7,484,568		(12,080,652)
5.2	James River Royalty Offset	441,934		(713,315)
5.3	Colstrip 3 Removal	314,398	(8,567,345)	(1,516,931)

6.1	**Hydro Decommissioning**	**(3,781)**	**(212,765)**	**(18,966)**
6.4	**Vehicle Depreciation Study**	**74,724**	**(143,764)**	**(137,549)**
7.2	**Property Tax Expense**	**(70,366)**	**-**	**113,576**
7.3	**Renewable Energy Tax Credit**	**661,917**	**-**	**(1,068,383)**
7.4	**Power Tax ADIT Balance**	**-**	**(1,637,024)**	**(192,886)**
7.5	**Washington Low Income Tax Credit**	**(25,873)**	**-**	**41,761**
7.6-7.6.1	**Flow-through Adjustment**	**407,649**	**(9,662,969)**	**(1,796,539**
7.7	**Remove Deferred State Tax Expense and Balance**	**488,064**	**244,032**	**(759,018)**
7.8	**WA Public Utility Tax**	**524,708**	**-**	**(846,919)**
8.1	**Jim Bridger Mine Rate Base**	**(138,615)**	**26,734,872**	**3,373,837**
8.2	**Environmental Remediation**	**(171,517)**	**(250,034)**	**247,380**
8.3	**Customer Advances for Construction**	**-**	**(481,414)**	**(56,724)**
8.5-8.5.1	**Miscellaneous Rate Base**	**-**	**(20,135,895)**	**(2,372,561)**
8.6	**Powerdale Hydro Removal**	**(58,361)**	**97,700**	**105,710**
8.7	**Removal of Colstrip 4 AFUDC**	**17,991**	**(360,049)**	**(71,462)**
8.8	**Trojan Unrecovered Plant Adjustment**	**(99,762)**	**(83,643)**	**151,168**
8.9	**Customer Service Deposits**	**(2,710)**	**(3,361,134)**	**(391,659)**
8.11	**Misc. Asset Sales & Removals**	**4,540**	**-**	**(7,328)**
8.13	**Investor Supplied Working Capital**	**-**	**31,018,483**	**3,654,829**
	Sub-total Uncontested Adjustments	**$18,209,423**	**$12,949,127**	**$(27,865,606)**

APPENDIX C - CONSOLIDATED DOCKETS

DETERMINATIONS IN DOCKETS

UE-131384 (COLSTRIP DEFERRAL),
UE-132350 (DEPRECIATION DEFERRAL),
UE-140094 (HYDRO DEFERRAL),
and
UE-140617 (MERWIN FISH COLLECTOR PROJECT DEFERRAL)

Cost Deferrals	Allowed Amounts to Amortize in Schedule 92
Colstrip Deferral (UE-131384)	**$0.00**
Depreciation Deferral (UE-132350)	**($877,345)**
Hydro Deferral (UE-140094)	**$0.00**
Merwin Fish Collector Project Deferral (UE-140617)	**$529,312**
TOTAL	**($348,033)**

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a	)	**File No. ER-2014-0258**
Ameren Missouri's Tariff to Increase Its	)	Tariff No. YE-2015-0003
Revenues for Electric Service	)	

REPORT AND ORDER

Issue Date: April 29, 2015

Effective Date: May 12, 2015

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	)))	**File No. ER-2014-0258** Tariff No. YE-2015-0003

APPEARANCES

Wendy K. Tatro, Director and Asst. General Counsel, and **Matthew Tomc**, Corporate Counsel, Union Electric Company, d/b/a Ameren Missouri, P.O. Box 66149, St. Louis, Missouri 63103;

James B. Lowery, Attorney at Law, and **Sarah Giboney**, Attorney at Law, Smith Lewis, LLP, P.O. Box 918, Suite 200, City Centre Building, 111 South Ninth St. Columbia, Missouri 65205-0918; and

L. Russell Mitten, Attorney at Law, Brydon, Swearengen & England, 312 E. Capital Ave., Jefferson City, Missouri 65102.

For Union Electric Company, d/b/a Ameren Missouri.

Kevin Thompson, Chief Staff Counsel; **John D. Borgmeyer**, Deputy Staff Counsel; **Colleen M. "Cully" Dale**, Senior Staff Counsel; **Jeffrey A. Keevil**, Senior Staff Counsel; **Cydney D. Mayfield**, Senior Staff Counsel; **Alexander Antal**, Assistant Staff Counsel; and **Jamie Myers**, Rule 13 Certified Law Student, P.O. Box 360, 200 Madison Street, Jefferson City, Missouri 65102

For the Staff of the Missouri Public Service Commission.

Dustin J. Allison, Public Counsel; **Tim Opitz**, Legal Counsel; **Marc Poston**, Legal Counsel; and **Christina Baker**, Legal Counsel, P.O. Box 2230, 200 Madison Street, Suite 650, Jefferson City, Missouri 65102

For the Office of the Public Counsel and the Public.

Ollie Green, Senior Legal Counsel, P.O. Box 1157, Jefferson City, Missouri 65102

For the Missouri Department of Economic Development – Division of Energy.

David Woodsmall, Attorney at Law, Woodsmall Law Office, 308 East High St., Suite 204, Jefferson City, Missouri 65101

For the Midwest Energy Consumers Group.

Diana Vuylsteke, Attorney at Law; **Kenneth J. Mallin**, Attorney at Law; **Elizabeth Carver**, Attorney at Law; **Edward F. Downey**, Attorney at Law; and **Carol Iles**, Attorney at Law, Bryan Cave, LLP, 211 N. Broadway, Suite 3600, St. Louis, Missouri 63102

For Missouri Industrial Energy Consumers.

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For the Consumers Council of Missouri.

Marc H. Ellinger, Attorney at Law; and **Stephanie S. Bell**, Attorney at Law, Blitz, Bardgett & Deutsch, L.C. 308 East High Street, Suite 301, Jefferson City, Missouri 65101.

For the Missouri Retailers Association.

Henry B. Robertson, Attorney at Law, Great Rivers Environmental Law Center, 705 Olive St., Suite 614, St. Louis, Missouri 63101;

Sunil Bector, Attorney at Law, Sierra Club, 85 Second St., 2nd Floor, San Francisco, California 94105; and

Thomas Cmar, Attorney at Law, Earthjustice, 5042 N. Leavitt St., Suite 1, Chicago, Illinois 60625.

For Sierra Club.

Sherrie A. Hall, Attorney at Law; **Emily R. Perez**, Hammond and Shinners, P.C. 7730 Carondelet Ave., Suite 200, St. Louis, Missouri 63105.

For International Brotherhood of Electrical Workers Local 1439.

Leland B. Curtis, Attorney at Law; **Carl J. Lumley**, Attorney at Law; and **Edward J. Sluys**, Attorney at Law, Curtis, Heinz, Garrett & O'Keefe, P.C., 130 S. Bemiston, Suite 200, St. Louis, Missouri 63105.

For the City of O'Fallon and the City of Ballwin.

David C. Linton, Attorney at Law, 314 Romaine Spring View, Fenton, Missouri 63026.

For United for Missouri, Inc.

Rick D. Chamberlain, Behrens, Wheeler & Chamberlain, 6 N.E. 63rd St., Suite 400, Oklahoma City, Oklahoma 73015, and

Marcos A. Barbosa, Baker Sterchi Cowden & Rice, LLC., 2400 Pershing Road, Suite 500, Kansas City, Missouri 64018.

For Wal-Mart Stores East, L.P. and Sam's East, Inc.

CHIEF REGULATORY LAW JUDGE: Morris L. Woodruff

REPORT AND ORDER

Table of Contents

The Missouri Public Service Commission, having considered all the competent and substantial evidence upon the whole record, makes the following findings of fact and conclusions of law. The positions and arguments of all of the parties have been considered by the Commission in making this decision. Failure to specifically address a piece of evidence, position, or argument of any party does not indicate the Commission has failed to consider relevant evidence, but indicates rather that the omitted material was not dispositive of this decision.

Summary

This order allows Ameren Missouri to increase the revenue it may collect from its Missouri customers by approximately $108 million, based on the data contained in the Revised True-up Reconciliation filed by the Missouri Public Service Commission Staff on March 28, 2015.[1] Approximately $103 million of that increase is related to Ameren Missouri's increased net fuel costs and would otherwise be recovered by the company through its fuel adjustment clause.

Procedural History

On July 3, 2014, Union Electric Company, d/b/a Ameren Missouri filed a tariff designed to implement a general rate increase for electric service. The tariff would have increased Ameren Missouri's annual electric revenues by approximately $264 million. The tariff revisions carried an effective date of August 2.

By order issued on July 11, the Commission suspended Ameren Missouri's general rate increase tariff until May 30, 2015, the maximum amount of time allowed by the controlling statute.[2] In the same order, the Commission directed that notice of Ameren Missouri's tariff filing be provided to interested parties and the public. The Commission also established July 31 as the deadline for submission of applications to intervene. The following parties filed applications and were allowed to intervene: The International Brotherhood of Electrical Workers Local 1439; The Missouri Industrial Energy Consumers (MIEC);[3] The Midwest Energy Consumers Group (MECG);[4] The Missouri Department of

[1] This number is only an estimate of the overall impact of the decisions described later in this report and order. This estimate does not in any way control or modify those decisions.

[2] Section 393.150, RSMo 2000.

[3] The members of MIEC are as follows: Anheuser-Busch Companies, Inc.; Ardagh Glass;

Economic Development – Division of Energy; The Consumers Council of Missouri; The Missouri Retailers Association; Sierra Club; The City of O'Fallon and the City of Ballwin; Earth Island Institute d/b/a Renew Missouri; the Natural Resources Defense Council; United for Missouri, Inc.; Wal-Mart Stores East, L.P. and Sam's East, Inc.; and United Steelworkers Union. On August 20, the Commission established the test year for this case as the 12-month period ending March 31, 2014, trued-up as of December 31, 2014. In its August 20 order, the Commission also established a procedural schedule leading to an evidentiary hearing.

In January 2015, the Commission conducted twelve local public hearings at various sites around Ameren Missouri's service area. At those hearings, the Commission heard comments from Ameren Missouri's customers and the public regarding Ameren Missouri's request for a rate increase.

In compliance with the established procedural schedule, the parties prefiled direct, rebuttal, and surrebuttal testimony. The evidentiary hearing began on February 23 and continued through March 12. The parties indicated they had no contested true-up issues and the Commission cancelled the scheduled true-up hearing. The parties filed post-hearing briefs on March 31, with reply briefs following on April 10.

The Partial Stipulations and Agreements

During the course of the evidentiary hearing, various parties filed nine non-unanimous partial stipulations and agreements resolving issues that would otherwise have

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BioKyowa, Inc.; The Boeing Company; Doe Run; Enbridge Energy; General Motors Corporation; GKN Aerospace; Hussmann Corporation; JW Aluminum; Mallinckrodt; Monsanto; Nestlé Purina PetCare; Noranda Aluminum; and SunEdison Semiconductors.

[4] The members of MECG are Continental Cement Company, LLC; Buzzi Unicem USA; Missouri Ethanol LLC, d/b/a POET Biorefining – Laddonia; Cargill; Tyson Foods; Explorer Pipeline Company, Maritz Holdings, Inc.; and Wal-Mart Stores, Inc. Wal-Mart subsequently was granted intervention on its own behalf.

been the subject of testimony at the hearing. No party opposed seven of those partial stipulations and agreements. As permitted by its regulations, the Commission treated the unopposed partial stipulations and agreements as unanimous.[5] After considering the stipulations and agreements, the Commission approved them as a reasonable resolution of the issues addressed in those agreements. The issues resolved in those stipulations and agreements will not be further addressed in this report and order, except as they may relate to any unresolved issues.

The other two non-unanimous stipulations and agreements were objected to by one or more parties. As provided in the Commission's rules, the Commission will treat those stipulations and agreements as merely a position of the signatory parties to which no party is bound.[6] The issues that were the subject of those stipulations and agreements will be determined in this report and order.

Pending Motion

On April 7, the Department of Economic Development (DED) filed an *amicus curiae* brief, accompanied by a petition seeking leave to file the brief. DED is not a party to this case, although the Division of Energy within the Department is a party and filed its own brief. On April 10, two parties, MECG and United for Missouri, filed pleadings opposing DED's petition.

The filing of *amicus* briefs at the Commission is governed by Commission Rule 4 CSR 240-2.075(11), which, among other things, requires that the *amicus* brief be filed no later than the initial briefs of the parties. The initial briefs were filed in this case on March 31. DED delayed filing its amicus brief until April 7; only three days before reply briefs were

[5] Commission Rule 4 CSR 240-2.115(C).

[6] Commission Rule 4 CSR 240-2.115(2)(D).

filed, severely limiting the other parties' opportunity to respond to the *amicus* brief. DED's motion for leave to file *amicus* brief does not comply with the Commission's rule and will be denied.

Admission of True-Up Testimony

A true-up hearing to deal with issues arising from the true-up of Ameren Missouri's costs as of the end of the true-up period on December 31, 2014, was scheduled for March 25. Laura Moore filed Revised True-Up Direct testimony on behalf of Ameren Missouri, Matthew Barnes filed Second Corrected True-Up Direct testimony on behalf of Staff, and Ted Robertson filed True-Up Direct testimony on behalf of Public Counsel.

No party asked to cross-examine any witness, and the true-up hearing was canceled by order issued on March 24. The true-up testimony is assigned the following exhibit numbers and is admitted into evidence.

Moore Revised True-Up Direct	Exhibit 74
Barnes Second Corrected True-Up Direct	Exhibit 247
Robertson True-Up Direct	Exhibit 413

Overview

Ameren Missouri is an investor-owned integrated electric utility providing retail electric service to large portions of Missouri, including the St. Louis Metropolitan area. Ameren Missouri has approximately 1.2 million retail electric customers in Missouri, more than 1 million of whom are residential customers.[7] Ameren Missouri also operates a natural gas utility in Missouri, but the rates it charges for natural gas are not at issue in this case.

[7] Moehn Direct, Ex. 28, Page 4, Lines 5-6.

Ameren Missouri began the rate case process when it filed its tariff on July 3, 2014. In doing so, Ameren Missouri asserted it was entitled to increase its retail rates by approximately $264 million per year, an increase of approximately 9.7 percent.[8] Ameren Missouri claimed a rate increase was necessary due to (a) increases in net fuel costs, largely driven by decreases in off-system sales due to lower power prices; (b) significant investments in infrastructure; (c) increases in income taxes and other taxes; (d) amortizations of solar rebate payments; and (e) changes in depreciation rates to reflect the retirement of the Meramec Energy Center by 2022.[9] The company attributed $103 million of that increase to the rebasing of fuel costs that would otherwise be passed through to customers by operation of the company's existing fuel adjustment clause.[10]

Ameren Missouri set out its rationale for increasing its rates in the direct testimony it filed along with its tariff on July 3, 2014. In addition to its filed testimony, Ameren Missouri provided work papers and other detailed information and records to the Staff of the Commission, Public Counsel, and to the intervening parties. Those parties then had the opportunity to review Ameren Missouri's testimony and records to determine whether the requested rate increase was justified.

Where the parties disagreed, they prefiled written testimony to raise those issues to the attention of the Commission. All parties were given an opportunity to prefile three rounds of testimony – direct, rebuttal, and surrebuttal. The process of filing testimony and responding to the testimony filed by other parties revealed areas of agreement that resolved some issues and areas of disagreement that revealed new issues. On February

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[8] Moehn Direct, Ex. 28, Page 5, Lines 8-9.

[9] Moehn Direct, Ex. 28, Page 5, Lines 10-20.

[10] Ameren Missouri Initial Post Hearing Brief, Page 2, Footnote 2.

18, the parties filed a list of the issues they asked the Commission to resolve. Some of the issues identified at that time were later resolved by unanimous stipulation and agreement. The unresolved issues will be addressed in this report and order.

Conclusions of Law Regarding Jurisdiction

A. Ameren Missouri is a public utility, and an electrical corporation, as those terms are defined in Section 386.020(43) and (15), RSMo (Cum. Supp. 2013). As such, Ameren Missouri is subject to the Commission's jurisdiction pursuant to Chapters 386 and 393, RSMo 2000.

B. Section 393.140(11), RSMo 2000, gives the Commission authority to regulate the rates Ameren Missouri may charge its customers for electricity. When Ameren Missouri filed a tariff designed to increase its rates, the Commission exercised its authority under Section 393.150, RSMo 2000, to suspend the effective date of that tariff for 120 days beyond the effective date of the tariff, plus an additional six months.

Conclusions of Law Regarding the Determination of Just and Reasonable Rates

A. In determining the rates Ameren Missouri may charge its customers, the Commission is required to determine that the proposed rates are just and reasonable.[11] Ameren Missouri has the burden of proving its proposed rates are just and reasonable.[12]

B. In determining whether the rates proposed by Ameren Missouri are just and reasonable, the Commission must balance the interests of the investor and the

[11] Section 393.150.2, RSMo 2000.

[12] Section 393.150.2, RSMo 2000.

consumer.[13] In discussing the need for a regulatory body to institute just and reasonable rates, the United States Supreme Court has held as follows:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[14]

In the same case, the Supreme Court provided the following guidance on what is a just and reasonable rate:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. 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.[15]

The Supreme Court has further indicated:

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure

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[13] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603, (1944).

[14] *Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 690 (1923).

[15] *Bluefield,* at 692-93.

> confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[16]

C. In undertaking the balancing required by the Constitution, the Commission is not bound to apply any particular formula or combination of formulas. Instead, the Supreme Court has said:

> Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.[17]

D. Furthermore, in quoting the United States Supreme Court in *Hope Natural Gas*, the Missouri Court of Appeals said:

> [T]he Commission [is] not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' … Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed which is controlling. It is not theory but the impact of the rate order which counts.[18]

The Rate Making Process

The rates Ameren Missouri will be allowed to charge its customers are based on a determination of the company's revenue requirement. Ameren Missouri's revenue requirement is calculated by adding the company's operating expenses, its depreciation on plant in rate base, taxes, and its rate of return multiplied by its rate base. The revenue requirement can be expressed as the following formula:

Revenue Requirement = E + D + T + R(V-AD+A)
Where: E = Operating expense requirement
D = Depreciation on plant in rate base
T = Taxes including income tax related to return

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[16] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (citations omitted).

[17] *Federal Power Commission v. Natural Gas Pipeline Co*. 315 U.S. 575, 586 (1942).

[18] *State ex rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n*, 706 S.W. 2d 870, 873 (Mo. App. W.D. 1985).

R = Return requirement
(V-AD+A) = Rate base
For the rate base calculation:
V = Gross Plant
AD = Accumulated depreciation
A = Other rate base items

All parties accept the basic formula. Disagreements arise over the amounts that should be included in the formula.

The Issues

1. Regulatory Policy and Economic Considerations.

This is not a true issue in that the parties do not ask the Commission to resolve any questions regarding the particulars of Ameren Missouri's request for a rate increase. Instead, the parties presented testimony regarding general policy matters that affect the Commission's decision making regarding the detailed issues that will be addressed later in this report and order. Because this is only a general policy discussion, the Commission will not make findings of fact or conclusions of law about these policy matters.

Testimony was offered by the parties regarding the difficult economic situation that is currently facing individuals and businesses in Missouri in general and in Ameren Missouri's service territory in particular. Aside from the testimony offered at the evidentiary hearing, the Commission also heard that message from Ameren Missouri's customers during the twelve, well-attended, local public hearings the Commission conducted throughout Ameren Missouri's service territory.

The Commission was created to serve the public interest, and it takes that responsibility very seriously. The Commission serves the public interest by establishing just and reasonable rates, and the Commission has endeavored to do so in this report and order.

Many customers are already having a hard time paying their electric bills. Increasing Ameren Missouri's rates may make it even harder for some customers to pay their bills. However, a just and reasonable rate does not necessarily mean a lower rate.

2. Weather Normalization (SPS and LGS Classes)

What level of sales to Noranda should be assumed for the test year for purposes of establishing billing units?

Findings of Fact:

1. Although this issue is described as weather normalization, it has little to do with the weather. Rather it concerns the amount of electricity that Ameren Missouri sells to Noranda for its New Madrid smelter. Noranda is Ameren Missouri's largest customer, representing over ten percent of Ameren Missouri's retail sales. Historically, it has a very stable and consistent load that varies very little while the aluminum smelter is in full production.[19] Given its unique characteristics, Noranda has its own rate as the only member of the Large Transmission Service (LTS) rate class.

2. During the test year for this case, which was the twelve months ending March 31, 2014, Ameren Missouri sold Noranda approximately 4.2 million mega-watt hours (MWhs) of electricity. Staff proposes to use that figure to set Ameren Missouri's rate.[20]

3. Beginning in July 2014, Noranda began to experience a production slow-down due to an unusually high number of "pot" failures. The lower production means Noranda bought less electricity from Ameren Missouri during that period. However, Noranda anticipated returning to full production by the end of March 2015.[21]

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[19] Wills Amended Rebuttal, Ex. 53, Pages 17-18, Lines 22-23, 1-2.

[20] Staff Report – Revenue Requirement, Ex. 202, Page 66, Lines 14-17.

[21] Phillips Surrebuttal, Ex. 516, Page 4, Lines 1-11.

4. Ameren Missouri is concerned about the drop in production and the corresponding drop in sales. In its rebuttal testimony, Ameren Missouri proposed to set the measure of sales to Noranda based on the actual sales in November and December of 2014, the last two months of the true-up period. That would result in an annual level of approximately 3.8 million MWhs.[22]

5. At the hearing, Ameren Missouri amended its position to propose the use of a three-year average to determine the level of sales. The three-year average would include the most recent year in which Noranda saw decreased production due to the pot failures. That would result in an annual level of approximately 4.1 million MWhs.[23]

6. As an alternative for the Commission's consideration, Ameren Missouri also offered a ten-year average calculation that results in an annual level of approximately 4.0 million MWhs.[24] However, that ten year average would include 2009 when Noranda's production was cut nearly in half by a power outage resulting from a severe ice storm.[25] Ameren Missouri suggested the ten-year average including the reduced production due to the ice storm would be appropriate if the Commission denies the company's request to recover costs deferred under an AAO related to that ice storm.[26]

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

In setting Ameren Missouri's volumetric rates to allow it to recover its costs to serve

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[22] Wills Amended Rebuttal, Ex. 53, Page 20, Lines 1-11.

[23] Wills Surrebuttal, Ex. 54, Page 8, Table SMW-2.

[24] Wills Surrebuttal, Ex. 54, Page 8, Table SMW-2.

[25] Wills Surrebuttal, Ex. 54, Page 6, Table SMW-1.

[26] Wills Surrebuttal, Ex. 54, Page 7, Lines 11-16.

Noranda, the Commission must determine how many billing units the company is likely to sell to Noranda in a year. The costs are then divided over the billing units to set the rate. If Ameren Missouri is able to sell more billing units than were factored into the rate, it collects more money than its cost to serve. Conversely, if it sells fewer units than were factored into its rate, it will not cover its full cost.

The Commission anticipates that Noranda will return to full production while the rates set in this case remain in effect, which is also the production level experienced in the test year. Setting its rate based on the test year experience will allow Ameren Missouri a fair opportunity to recover its cost to serve Noranda. If the Commission were to set those rates based on an average number that includes the unusually reduced production resulting from the ice storm in 2009, or the elevated level of pot failures in 2014, Ameren Missouri would be in a position to collect a windfall if, as anticipated, Noranda returns to full production in 2015.

Of course, there is a possibility that Noranda will not return to full production as anticipated, but Ameren Missouri's shareholders should bear the business risk of reduced sales, not its ratepayers. The Commission will set the level of annual billing units at 4.2 million Mega-Watt hours (MWh) of electricity as recommended by Staff.

3. Income Tax

A. Should Ameren Missouri's Net Operating Loss Carryforward Related to ADIT be included in Ameren Missouri's rate base?

Findings of Fact:

1. This issue concerns Ameren Missouri's test year Net Operating Loss Carryforward (NOLC) associated with its Accumulated Deferred Income Tax (ADIT)

balance.

2. ADIT represents assets or liabilities for cumulative amounts of deferred income taxes resulting from differences between book accounting and income-tax accounting.[27] For example, tax law sometimes allows a company to claim accelerated depreciation in calculating its taxes.[28]

3. Since in the short term it pays less in taxes, the company is able to keep more cash. But, because the company can only depreciate its assets once, the accelerated depreciation will reduce the depreciation expense the company would otherwise use to reduce its taxes in future years. Essentially the ADIT allows the company to have the use of "free" cash between the time the ADIT is acquired and the time the increased taxes will come due.[29] Because the ADIT represents "free" cash to the company, ratepayers should not be required to pay for it and the company should not be allowed to earn a return on it. Thus ADIT is removed from the company's ratebase.[30]

4. However, when bonus depreciation and other tax deductions grow so large as to push the company's taxable income into the negative, the available tax deduction cannot offset any tax liability and no "free" cash is generated. In that circumstance, the company must record an offsetting deferred tax asset for Net Operating Loss Carryforward (NOLC). The NOLC offsets the ADIT, which would decrease the company's rate base, and therefore, the NOLC has the effect of increasing the rate base.[31]

5. For many years, Ameren Corporation, of which Ameren Missouri is an

[27] Brosch Direct, Ex. 501, Page 13, Lines 4-14.

[28] Brosch Direct, Ex. 501, Page 13, Lines 15-21.

[29] Warren Rebuttal, Ex. 48, Pages 11-12.

[30] Brosch Direct, Ex. 501, Page 15, Lines 1-17.

[31] Brosch Surrebuttal, Ex. 502, Page 5, Lines 18-23.

affiliate, has filed a consolidated tax return on behalf of itself and all its subsidiary corporations, including Ameren Missouri. Filing a consolidated return means that all tax losses of the group are used to offset the taxable income of the entire group.[32] Filing a consolidated tax return benefits Ameren Corporation and in most years benefits Ameren Missouri as well. Furthermore, once a company chooses to file a consolidated tax return, it cannot switch to filing separate returns for its affiliates except by special permission from the IRS.[33]

6. For tax years 2008 through 2012, the calculation of NOLC allocated to Ameren Missouri through the filing of a consolidated return had the effect of substantially increasing the NOLC allocated to Ameren Missouri, and thus decreasing the company's rate base.[34] In 2013 and 2014, Ameren Missouri produced a large amount of taxable income but could not use that accumulated NOLC because the Ameren group as a whole had a tax loss.[35] As a result, the NOLC is larger than it would otherwise be and rate base is approximately $51.1 million larger at the end of 2014 than it would be if Ameren Missouri had filed a separate tax return.[36] However, in future years, the balance could switch back, and Ameren Missouri's ratepayers would once again benefit from the use of the consolidated return.[37]

7. Rather than use Ameren Missouri's actual NOLC that was determined using the consolidated tax return actually filed, MIEC's witness, Michael Brosch, urges the

[32] Warren Rebuttal, Ex. 48, Page 18, Lines 12-17.
[33] Warren Rebuttal, Ex. 48, Page 23, Lines 14-18.
[34] Warren Rebuttal, Ex. 48, Page 26, Table VII.
[35] Brosch Direct, Ex. 501, Page 25, Lines 16-21.
[36] Brosch Surrebuttal, Ex. 502, Schedule MLB-10, page 2.
[37] Transcript, Page 360, Lines 4-10.

Commission to recalculate NOLC as if Ameren Missouri had filed a separate tax return.[38] However, he does not argue that the separate tax return, stand-alone, calculation should necessarily be used in future rate cases. Rather he argues the Commission should calculate NOLC in each future case by the method that creates the lowest NOLC rate base addition, to the benefit of ratepayers and the detriment of the company.[39]

8. Ameren Corporation and its affiliated companies have entered into a Tax Allocation Agreement that governs the allocation of consolidated annual income tax responsibility among the members of the consolidated tax group and defines the amounts recorded on the utility's books.[40]

9. There is no evidence in this case to show that Ameren's Tax Allocation Agreement is structured in a way that would be detrimental to Ameren Missouri and its ratepayers. Instead, for several years, Ameren Missouri's ratepayers benefited from a lower rate base because of the Tax Allocation Agreement. The Tax Allocation Agreement has not changed, but in more recent years ratepayers have not benefitted from that agreement, although that may change again in the future. That fluctuation does not mean the agreement is unreasonable, and there is no evidence the fluctuation was intentionally created in order to change who benefits from the Tax Allocation Agreement.

Conclusions of Law:

A. MIEC points to the Commission's affiliate transaction rule as support for its proposal to calculate NOLC in whichever manner results in the lower rate base for the company. Commission Rule 4 CSR 240-20.015(2) says:

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[38] Brosch Direct, Ex. 501, Page 26, lines 14-18.

[39] Brosch Surrebuttal, Ex. 502, Page 6, Lines 19-25.

[40] Brosch Surrebuttal, Ex. 502, Page 6, Lines 8-12.

(2) Standards.

(A) A regulated electrical corporation shall not provide a financial advantage to an affiliated entity. For the purposes of this rule, a regulated electrical corporation shall be deemed to provide a financial advantage to an affiliated entity if –

1. It compensates an affiliated entity for good or services above the lesser of –

A. The fair market price; or

B. The fully distributed cost to the regulated electrical corporation to provide the goods or services for itself; or

2. It transfers information, assets, goods or services of any kind to an affiliated entity below the greater of –

A. The fair market price; or

B. The fully distributed cost to the regulated electrical corporation.

B. Section 4 CSR 240-20.015(1)(B) defines affiliate transaction as:

Affiliate transaction means any transaction for the provision, purchase or sale of any information, asset, product or service, or portion of any product or service, between a regulated electrical corporation and an affiliated entity, …

C. The Commission's affiliate transaction rules do not apply in this situation because there is no transaction involved. The affiliate transaction rules are intended to control transfers of goods or services between regulated utilities and their affiliates. So for example, if Ameren Missouri wants to purchase legal services from an affiliate such as Ameren Services Company, it cannot pay more than the lesser of market cost or its cost to provide the services for itself. In that context that is a reasonable restriction to ensure the regulated utility is not giving a sweetheart contract to an affiliate at the ratepayers' expense.

D. But here, where there is no transaction, the restrictions of the rule have no meaning. How could the fair market price or the fully distributed cost even be calculated? MIEC can only fall back to the basic policy behind the affiliate transaction rule, which reasonably states that regulated utilities should not be allowed to structure corporate arrangements in a way that disadvantages regulated utilities and thereby disadvantages ratepayers.

Decision:

Ameren Missouri proposes to use the NOLC it has actually accumulated rather than a hypothetical NOLC proposed by MIEC and supported by Staff, MIEC advocates a policy that arrangements between affiliates should always be interpreted in a manner that benefits ratepayers, even if that results in a detriment to the utility. There is no basis in law or fact for such a policy. The Commission must balance the interests of ratepayers and shareholders to set just and reasonable rates. Ameren Missouri's position is fair and will be adopted.

B. Should the Company's IRC Section 199 Deduction be computed without regard to Net Operating Loss Carryovers from prior years in determining the Company's income tax expense?

Findings of Fact:

1. The Internal Revenue Code Section 199 deduction is also referred to as the domestic production deduction or DPD. The DPD is a tax incentive provided to manufacturers, including producers of electricity. It allows the tax payer to take a tax deduction equal to 9% of the lesser of certain qualified net income or the taxpayer's taxable income. Under the tax law, the DPD is calculated on a consolidated basis.[41] Recognition of a DPD would reduce Ameren Missouri's tax expense and would therefore reduce rates for ratepayers.

2. In its initial filing for this case, Ameren Missouri calculated a DPD of $30.8 million.[42] MIEC's witness, Michael Brosch recalculated that deduction at $36.9 million in

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[41] Warren Rebuttal, Ex. 48, Page 31, Lines 6-12.

[42] Brosch Direct, Ex. 501, Page 9, Lines 21-23.

his direct testimony.[43]

3. In his rebuttal testimony, Ameren Missouri's witness, James Warren, testified that both Mr. Brosch and Ameren Missouri's initial calculation of the DPD are incorrect. Both calculations assumed that Net Operating Loss Carryforward (NOLC) was not includable. In fact, Mr. Warren explained that Treasury Regulations applicable to the DPD do allow for the consideration of NOLC in calculating DPD.[44] Including the NOLC in the calculations would reduce Ameren Missouri's taxable income and thereby reduce the DPD.[45]

4. Ameren Missouri has not utilized NOLC in its calculation of its DPD in past rate cases and only proposed to do so in rebuttal testimony offered in this case. Both MIEC[46] and Staff[47] contend the use of NOLC should not be allowed because it has not been used in the past. MIEC's witness, Michael Brosch, also expressed concern that the NOLC should not be used because of the uncertainty that Ameren Missouri will even have an NOLC in future years.[48]

5. As an alternative to totally eliminating consideration of NOLC in calculating the DPD, MIEC proposed a DPD calculation that uses only the NOLC that would be calculated assuming that Ameren Missouri had filed a separate tax return rather than the

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[43] Brosch Direct, Ex. 501, Schedule MLB-4, Page 2.

[44] Warren Rebuttal, Ex. 48, Pages 32-33, Lines 11-25, 1-2.

[45] Hanneken Surrebuttal, Ex. 218, Page 14, Lines 11-13. The testimony calculates an amount of the deduction that is listed as highly confidential so will not be stated in this order.

[46] Brosch Surrebuttal, Ex. 502, Page 22, lines 5-8. See also, Transcript, Pages 410-411, Lines 17-25, 1.

[47] Hanneken Surrebuttal, Ex. 218, Page 15, Lines 1-6. *See also*, Transcript, Page 375, Lines 17-22.

[48] Transcript, Page 411, Lines 2-14.

consolidated return it actually files with Ameren Corporation and its affiliates. That calculation supported a DPD estimate of $7.9 million.[49]

6. The use of a hypothetical stand-alone tax return in place of the actual consolidated return is the same issue as was addressed in the previous income tax issue. All parties agree the question should be resolved in the same way for both sub-issues.

Conclusions of Law:

The Commission makes no additional conclusions of law for this sub-issue.

Decision:

Ameren Missouri demonstrated that the Internal Revenue Code allows for the use of NOLC in calculating Ameren Missouri's DPD. The Internal Revenue Code does not require the Commission to allow its use for regulatory purposes, but the fact that NOLC has not been included in that calculation in past rate cases is not a persuasive reason to forbid its inclusion in this case. MIEC's suggestion that inclusion of NOLC makes the DPD uncertain because Ameren Missouri may not have NOLC in the future is based only on speculation and on MIEC's failed effort to require NOLC to be calculated on a hypothetical stand-alone basis. The Commission concludes, consistent with its decision in the previous income tax issue, that Ameren Missouri's method for calculation of its DPD is appropriate.

4. Amortizations

A. Should the amount of solar rebates paid by Ameren Missouri and recorded to a solar rebate regulatory asset through the end of the true-up period be included in Ameren Missouri's revenue requirement using a 3-year amortization period?

Findings of Fact:

1. In a non-unanimous stipulation and agreement filed in Commission File No. ET-2014-0085, Ameren Missouri, Staff, Public Counsel, MIEC, and numerous other parties

[49] Brosch Surrebuttal, Ex. 502, Page 22-23, and Schedule MLB-4 Revised.

agreed that Ameren Missouri would continue to make the solar rebate payments required by Missouri's Renewable Energy Standard, Section 393.1030 RSMo (Cum. Supp. 2013), until a specified level of $91.9 million in rebates was incurred by the company. That agreement also provides for creation of a regulatory asset to be considered for recovery in rates after December 31, 2013, in a general rate case. Ameren Missouri was required to record to that asset the actual amount of solar rebates paid, not to exceed $91.9 million, plus 10 percent.[50] No one objected to that stipulation and agreement, and the Commission approved it in an order issued on November 13, 2013.[51]

2. Ameren Missouri has deferred and accumulated approximately $88.1 million of solar rebates through December 31, 2014. Coupled with a 10 percent added cost of $8.8 million as provided in the stipulation and agreement, Ameren Missouri is seeking to recover approximately $96.9 million. By terms of the stipulation and agreement, that amount is to be amortized over three years, so $32.3 million would be included in Ameren Missouri's rates to be established in this case.[52]

3. MIEC and Consumers Council contend Ameren Missouri should not be allowed to recover any additional revenues to recover any of the solar rebate expense deferred under the stipulation and agreement. They assert that Ameren Missouri's earnings from retail rates during the period when the rebate costs were incurred already covered those costs.[53] Essentially, they argue that Ameren Missouri over-earned during the period the costs were incurred, so it should not be allowed to again recover those costs

[50] Ex. 55.

[51] *In the Matter of Ameren Missouri's Application for Authorization to Suspend Payment of Solar Rebates*, Order Approving Stipulation and Agreement, File No. ET-2014-0085, November 13, 2013.

[52] Cassidy Surrebuttal, Ex. 211, Page 4, Lines 3-11.

[53] Meyer Direct, Ex. 513, Pages 11-12, Lines 18-21, 1-2.

in the rates to be established in this case.

4. As proof that Ameren Missouri has over-earned, MIEC and Consumers Council point to Ameren Missouri's raw, unadjusted surveillance reports to claim that for most of the period from August 2012 through September 2014, Ameren Missouri collected enough revenue above its authorized revenue level to fully recover its solar rebate payments.[54]

5. However, unadjusted, per-book surveillance reports have only a limited value.[55] In the recent rate complaint case, the complainants attempted to use the same, slightly adjusted surveillance reports as the basis for setting new rates. In rejecting that attempt, the Commission found:

> It is important to understand that the earnings levels reported in the surveillance reports are actual per book earnings of the utility and cannot be compared directly to an authorized return on equity to determine whether a utility is overearning. Actual per book earnings are often computed differently than earnings used for the purpose of establishing rates. When setting rates, the Commission looks at "normal" levels of ongoing revenues and expenses, while book earnings can be affected by abnormal, non-recurring and extraordinary events. A good example of this is the weather.[56]

In this case, MIEC's witness, Greg Meyer simply pointed to the surveillance reports, without making any adjustments, to claim that Ameren Missouri has been over-earning. The Commission finds that the unadjusted per-book surveillance reports are not sufficient to establish that Ameren Missouri over-earned during the period of deferral.

6. Even if the unadjusted per-book surveillance reports were accepted as the basis for a claim of over-earning, the over-earning they purport to show is not significant.

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[54] Meyer Direct, Ex. 513, Page 13 and Schedule GRM-3.

[55] Transcript, Page 536, Lines 9-10.

[56] *Noranda Aluminum, Inc., et al. v. Union Electric Company*, File No. EC-2014-0223, Report and Order, October 1, 2014, Finding of Fact No. 13, Page 8.

For calendar year 2013, the per-book surveillance report showed that Ameren Missouri's actual earned return on equity was 10.34 percent, compared to an authorized return on equity of 9.8 percent.[57] For calendar year 2014, the per-book surveillance report showed that Ameren Missouri actual earned return on equity was 9.71 percent, again compared to an authorized return on equity of 9.8 percent.[58] Over the entire 2013 and 2014 period the per-book over-earning would amount to less than 0.50 percent.[59]

Conclusions of Law:

A. In 2008, Missouri voter adopted by initiative Proposition C, which creates a Renewable Energy Standard. That standard, which is codified in Sections 393.1025 and 393.1030 RSMo (Cum. Supp. 2013), requires investor-owned electric utilities, such as Ameren Missouri, to obtain a specified percentage of their electric generation from renewable energy resources, provided that the cost to do so does not raise retail rates by more than one percent. More specifically, Section 393.1030.3 requires investor-owned electric utilities to pay solar rebates to their customers who choose to install new or expanded solar energy generating facilities on their property.

B. Section 393.1030.2(4), RSMo (Cum. Supp. 2013), provides that the electric utility may seek to recover the costs of complying with the Renewable Energy Standard, including solar rebate payments, outside a regular rate case by means of a Renewable Energy Standard Rate Adjustment Mechanism (RESRAM). Ameren Missouri does not have a RESRAM, as will be explained later, but the inclusion of that possibility illustrates that the policy of the Renewable Energy Standard statute supports the recovery of those

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[57] Ex. 524.

[58] Ex. 528.

[59] Transcript, Page 585, Lines 9-14.

costs by the utility.

C. Section 393.1030.3 of the statute allows the utility to petition the Commission to cease payment of the solar rebates if paying additional rebates will cause the utility to exceed the allowable one percent increase in retail rates. Ameren Missouri filed such a petition in the fall of 2013. That petition was assigned File No. ET-2014-0085 by the Commission.

D. File No. ET-2014-0085 was ultimately resolved by a stipulation and agreement[60] that was approved by the Commission in an order issued on November 13, 2013.[61]

E. The stipulation and agreement allowed Ameren Missouri to discontinue paying solar rebates after it had paid a total of $91.9 million for rebates incurred after July 31, 2012. It provides that such solar rebate payments, with an additional ten percent carrying charge, are to be included in a regulatory asset to be considered for recovery in rates after December 31, 2013 in a general rate case. The stipulation and agreement also provides that the costs are to be amortized over three years when they are recovered in rates.

F. In the stipulation and agreement, the signatories agree "not to object to Ameren Missouri's recovery in retail rates of prudently paid solar rebates." There is a footnote to that statement which says:

> Given the Signatories' agreement that the specified amount should be paid, the only questions in future general rate proceedings regarding the recovery of solar rebate payments is whether the claimed solar rebate payments have been made and whether they were prudently paid under the Commission's

[60] Ex. 55.

[61] *In the Matter of Ameren Missouri's Application for Authorization to Suspend Payment of Solar Rebates*, Order Approving Stipulation and Agreement, File No. ET-2014-0085, November 13, 2013.

> RES rules and Ameren Missouri's tariff. 'Prudently paid' relates only to whether Ameren Missouri paid the proper amount due to an applicant for a rebate, paid it to the proper person or entity, and paid it in accordance with the Commission's RES rules and Ameren Missouri's tariffs.

In return, as part of the stipulation and agreement, Ameren Missouri gave up its right under the statute to seek recovery of the solar rebate costs outside a rate case through a RESRAM.

G. MIEC signed the stipulation and agreement, Consumers Council did not. Ameren Missouri contends MIEC has violated the terms of the stipulation and agreement by challenging Ameren Missouri's recovery of the solar rebate payments in this case on a basis other than prudent payment. As a remedy, it asks the Commission to strike all the testimony and argument offered by MIEC on this issue. Consumers Council did not sign the stipulation and agreement, and Ameren Missouri concedes that it can argue against recovery of the solar rebates on any basis that it wishes. However, Ameren Missouri asserts that MIEC procured the services of Consumers Council's witness, James Dittmer, on behalf of Consumers Council and, on that basis, asks the Commission to strike his testimony as well.

H. Commission rule 4 CSR 240-20.090(10) requires each electric utility with a fuel adjustment clause (a rate adjustment mechanism or RAM within the words of the regulation) to submit a quarterly Surveillance Monitoring Report. The required contents of the quarterly report are described by Commission rule 4 CSR 240-3.161(6). That regulation also requires that such reports be treated as highly confidential.

I. Rate making is designed to be forward looking. The goal is to choose a representative test year to estimate what costs will be when rates are in effect, not to make adjustments for past earning levels.[62] The practice of setting future rates to adjust for past earning levels is condemned as retroactive ratemaking that would deprive either the utility or its customers of their property without due process.[63]

J. The Commission only sets the rates that Ameren Missouri, or any other utility, may charge its customers. It does not determine a maximum or minimum return the utility may earn from those rates. Sometimes, the established rate will allow the utility to earn more than was anticipated when the rate was established. Sometimes, the utility will earn less than anticipated. But the rate remains in effect until it is changed by the Commission, and so long as the utility has charged the authorized rate, it cannot be made to refund any "over-earnings," nor can it be allowed to collect any "under-earnings" from its customers.[64]

Decision:

The Commission will fully address this issue on its merits and will not strike any testimony. This is not the proper forum to determine whether MIEC violated the terms of the stipulation and agreement or the order of the Commission that directed the signatories to comply with that agreement. If Ameren Missouri wishes to further pursue a remedy for what it believes to be a breach of the stipulation and agreement it may do so in a new proceeding of its choosing.

This issue is about the deferral of Ameren Missouri's solar rebate costs for consideration for recovery in this rate case. Generally, the Commission uses a test year to determine which of a utility's expenses will be considered when setting just and reasonable

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[62] *State ex rel. Southwestern Bell Tele. Co. v. Pub. Serv. Comm'n*, 645 S.W.2d 44, 48 (Mo. App. W.D. 1982).

[63] *State ex rel. Util. Consumers Council of Mo, Inc. v. Pub. Serv. Comm'n*, 585 S.W.2d 41, 58 (Mo. banc 1979).

[64] *Straube v. Bowling Green Gas Co.,* 227 S.W.2d 666 (Mo. 1950).

rates for the future. But sometimes the utility incurs an expense that the Commission believes should be deferred for consideration for recovery in a future rate case. The classic example is a severe storm that causes the electric utility to incur unexpectedly large costs. If that storm occurs outside the test year for the next rate case, the company would never be able to recover those unexpected costs.

But storms are not the only reason a deferral may be allowed. There may be other public or regulatory policy reasons why a utility should be allowed to defer a cost for consideration for recovery in a future rate case. For this issue, the costs that have been deferred are the costs Ameren Missouri paid to give rebates to its customers who installed home solar power generating units. The people of Missouri imposed the solar rebate requirement by voting for Proposition C because they believe that renewable energy in general, and solar energy in particular, is important to the well-being of our state. That legislation required Ameren Missouri and Missouri's other investor-owned electric utilities to be the conduit to encourage individuals to invest in solar energy. Therefore, it is entirely appropriate to allow Ameren Missouri to defer those costs for recovery in its next rate case.

As has been said many times, the deferral of a cost is not ratemaking treatment. That is, the deferral of a cost does not guarantee recovery of that cost in future rates. The Commission must determine within the context of a rate case whether recovery of the deferred cost is appropriate. But, usually the policy reason that justified the deferral still applies when it comes time to decide whether the deferred costs should be included when determining a future rate.

MIEC and the Consumers Council argue for what is in essence an earnings test to be applied to all deferrals. Under such a test, the Commission would have to determine by how many dollars a utility over-earned during the deferral and then, dollar for dollar, the Commission would have to deny recovery of every dollar deferred above the return authorized in the last rate case. Such an earnings test fundamentally misunderstands the ratemaking process and would be completely unworkable in practice.

The Commission sets rates in a forward looking process using a test year to evaluate the amount of revenue the utility needs to earn to recover its costs and to have a reasonable opportunity to earn a profit. The utility is not guaranteed a profit, just an opportunity to earn that profit. Sometimes, circumstances make it difficult for the utility to earn that profit. Perhaps the summer is cooler than normal and people do not use their air conditioners so the utility does not sell as much electricity as anticipated. Or, perhaps, a generating plant goes down, resulting in unanticipated capital expenditures for the utility. Sometimes, circumstances favor the utility and it is able to earn more revenue than was anticipated when its rates were set. Whether the utility earns more or less revenue than was anticipated when the Commission set its rates does not necessarily indicate over- or under-earnings such that the utility's rate are no longer just and reasonable, though that can be one relevant factor of many to consider when setting new rates. Thus, in most cases, mention of over- or under-earnings is just a shorthand way of discussing whether the Commission should examine a utility's existing rates to determine if they are still just and reasonable. If Staff or some other party looks at the utility's earnings and finds that the utility is consistently earning above the benchmark return on equity established in the last rate case, they may, by filing a complaint, petition the Commission to again undertake the process of re-determining the utility's just and reasonable rates. If the utility looks at its earnings and finds it is not earning what it believes it should, it can begin the rate review process by filing a tariff to start the rate case process.

The surveillance reports that have been discussed extensively in this case were established to make that information about Ameren Missouri's earnings available to all interested stakeholders so that they could decide whether the process to establish a new rate should be undertaken. But those surveillance reports do not themselves determine what an appropriate rate should be, nor do they establish either a ceiling or a floor on the earnings of the utility. Most fundamentally, in isolation, surveillance reports do not establish that a utility has under or over earned for purposes of setting rates.

Ameren Missouri's solar rebate costs were appropriately deferred pursuant to the Commission order approving those costs and their deferral, and now may be recovered through the rates set in this rate case, amortized over three years. No offset for over-earnings is appropriate.

B. Should the amount of pre-MEEIA energy efficiency expenditures incurred by Ameren Missouri and recorded to a regulatory asset through the end of the true-up period be included in Ameren Missouri's revenue requirement and, if so, over what period should they be amortized?

Findings of Fact:

1. In previous rate cases, the Commission allowed Ameren Missouri to defer certain pre-MEEIA energy efficiency expenditures for subsequent recovery, amortized over several years. For this case, Ameren Missouri would defer and recover an additional $3.3 million in expenditures incurred between the July 31, 2012 true-up cutoff date and January 2, 2013 effective date of the report and order in Ameren Missouri's last rate case, ER-2012-0166, amortized over six years. Staff would also make certain adjustments to the

previously allowed deferrals.[65]

2. Ameren Missouri does not contest the treatment of these costs proposed by Staff.[66] MIEC once again opposes recovery of these deferrals because of the alleged over-earnings by Ameren Missouri.

Conclusions of Law:

A. The Missouri Energy Efficiency Investment Act,[67] generally known as MEEIA, is a statute designed to encourage electric utilities to invest in energy efficiency measures that will reduce the need to invest in energy production infrastructure. The goal of the statute is to make such investments profitable, and to that end, Section 393.1075.3 establishes the policy of the state to allow electric utilities to recover "all reasonable and prudent costs of delivering cost-effective demand-side programs."

Decision:

Public policy in Missouri, as indicated by MEEIA, favors allowing electric utilities to fully recover their expenditures on energy efficiency programs. As explained with regard to the Solar Rebate Payment Deferral issue, no offset for over-earnings is appropriate here. Deferral and recovery of the pre-MEEIA energy efficiency expenditures incurred by Ameren Missouri shall be made in the manner described by Staff.

C. Should the amount of Fukushima flood study costs incurred by Ameren Missouri and recorded to a regulatory asset be included in Ameren Missouri's revenue requirement and, if so, over what period should they be amortized?

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[65] Staff Report Revenue Requirement, Ex. 202, Page 58, Lines 17-20, and Pages 120-121, Lines 27-31, 1-6.

[66] Transcript, Page 543, Lines 1-7.

[67] Section 393.1075, RSMo (Cum. Supp. 2013).

Findings of Fact:

1. After the Fukushima Tsunami, the Nuclear Regulatory Agency required all U.S. utilities that operate nuclear power plants to perform a study of the threat of flooding at those facilities.[68] Staff and Ameren Missouri agree the $926,561 cost of the study should be deferred for recovery over a ten-year amortization period.[69] MIEC once again opposes recovery of these deferrals because of the alleged "over-earnings" by Ameren Missouri.

2. The deferral of the cost of the study is consistent with applicable accounting standards.[70]

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The deferral and recovery of the Fukushima study costs is consistent with good public and regulatory policy. Ameren Missouri may recover those costs, amortized over a ten-year period.

5. Noranda AAO

Should the sums authorized for deferral in Case No. EU-2012-0027 be included in Ameren Missouri's revenue requirement and, if so, over what period should they be amortized?

Findings of Fact:

1. On January 27-28, 2009, a major ice storm disrupted the power supply to Noranda's aluminum smelter. The molten aluminum hardened in two of the three

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[68] Transcript, Page 509, Lines 5-13.

[69] Staff Report Revenue Requirement, Ex. 202, Page 122, Lines 4-6.

[70] Transcript, Page 543, Lines 8-16.

production lines, and Noranda's output was reduced for most of that year. As a result, Noranda bought much less electricity from Ameren Missouri than had been anticipated when Ameren Missouri's rates were set. Because Noranda purchased less power from Ameren Missouri, the company was unable to recover a portion of the revenue it would otherwise have recovered through the sale of electricity to Noranda.[71]

2. On the same day as the start of the ice storm, January 27, 2009, the Commission issued a report and order in Ameren Missouri's (then AmerenUE's) rate case. In that report and order, the Commission for the first time granted the company's request for a fuel adjustment clause.[72]

3. The existence of the fuel adjustment clause exacerbated the problem Ameren Missouri faced because of the Noranda outage. Ameren Missouri could resell at least part of the power it would otherwise have sold to Noranda on the off-system sales market. But as an off-system sale, 95 percent of the revenue derived from that sale would flow through the FAC to be netted against fuel costs, and would therefore benefit ratepayers rather than Ameren Missouri's shareholders.[73]

4. Ameren Missouri tried to rectify that problem by filing an application for rehearing in the rate case seeking to have the newly minted Fuel Adjustment Clause modified. That motion was opposed by the other parties, and on February 19, 2009, the Commission denied the motion for rehearing, pointing out that it was not possible to reopen the record to take additional evidence and still conclude the case before the March 1, 2009

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[71] Cassidy Rebuttal, Ex. 210, Pages 2-3, Lines 15-23, 1-2.

[72] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, 18 Mo.P.S.C.3d 306 (2009).

[73] Cassidy Rebuttal, Ex. 210, Page 3, Lines 2-9.

operation of law date.[74]

5. In an attempt to get around the effect of the Fuel Adjustment Clause it had just obtained, Ameren Missouri sold part of the power it would otherwise have sold to Noranda under long-term supply contracts to American Electric Power Operating Companies (AEP) and Wabash Valley Power Association, Inc. In making those sales, Ameren Missouri believed it could avoid having to run the replacement sales through its fuel adjustment clause (FAC). But in a subsequent prudence review of the Fuel Adjustment Clause the Commission disagreed, finding that the sales to AEP and Wabash were off-system sales that had to be run through the FAC. Thus, 95 percent of the benefit of those sales was allotted to Ameren Missouri's ratepayers by operation of the FAC, and was not available to allow Ameren Missouri to cover its fixed costs that would otherwise have been recovered through sales to Noranda.[75]

6. Ameren Missouri appealed the Commission's order in the prudence review cases, but the Western District Court of Appeals affirmed the Commission's decision.[76] After the Commission issued its decision in the first prudence review, and while the appeal of that decision was pending, Ameren Missouri applied to the Commission for an Accounting Authority Order (AAO) seeking to defer fixed costs to serve Noranda that were

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[74] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Order Denying AmerenUE's Application for Rehearing, Case No. ER-2008-0318, 18 Mo.P.S.C.3d 441 (2009).

[75] Cassidy Rebuttal, Ex. 210, Pages 3-4, Lines 19-23, 1-8. The two prudence reviews cases in which the Commission made those rulings are: *In the Matter of the First Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of Union Electric Company, d/b/a Ameren Missouri*, Report and Order, File No. EO-2010-0255, April 27, 2011; and *In the Matter of the Second Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of Union Electric Company, d/b/a Ameren Missouri*, Report and Order, File No. EO-2012-0074, July 31, 2013.

[76] *State ex rel. Union Elec. Co. v. Public Service Com'n*, 399 S.W.3d 467 (Mo. App. W.D.2013).

not recovered because of the reduced sales to Noranda resulting from the ice storm.[77]

7. On November 26, 2013, the Commission issued a Report and Order granting Ameren Missouri the AAO it sought.[78] Public Counsel and MIEC appealed that decision to the Western District Court of Appeals. On January 13, 2015, the court issued a *per curium* order that affirmed the Commission.[79] An application for transfer to the Missouri Supreme Court was denied on April 28, 2015.

8. In its Report and Order granting the requested AAO, the Commission found that revenue not collected by a utility to recover its fixed costs could be an item to be deferred and considered for later ratemaking treatment. It also determined that Ameren Missouri's loss of $35,561,503, which constitutes 8.5 percent of its net income in that year, is extraordinary and material. However, the report and order merely grants the AAO to permit Ameren Missouri to defer the costs for consideration in a future rate case. It does not make any finding or decision that would indicate the costs will ultimately be recovered in rates. Indeed, the report and order specifically says that "deferred recording does not guarantee recovery in any later rate action; recovery may be granted in whole, partially, or not at all."[80]

9. Between the time the deferred costs were incurred by Ameren Missouri and

[77] Barnes Rebuttal, Ex. 3, Page 61, Lines 12-15.

[78] *In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for the Issuance of an Accounting Authority Order Relating to its Electrical Operations*, Report and Order, File No. EU-2012-0027, November 26, 2013.

[79] The Court's Order is attached to Barnes Rebuttal, Ex. 3, Schedule LMB-R9.

[80] *In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for the Issuance of an Accounting Authority Order Relating to its Electrical Operations*, Report and Order, File No. EU-2012-0027, November 26, 2013.

the present, the Commission has adjusted Ameren Missouri's rates in several rate cases.[81]

10. For the period between June 2007, through September 2014, Ameren Missouri has reported positive earnings.[82]

Conclusions of Law:

A. The fact that an AAO has been granted to defer these costs for consideration in this rate case does not mean Ameren Missouri is entitled to recover those costs. The granting of an AAO is not ratemaking and creates no expectation of recovery.[83] In discussing that expectation of recovery, the Missouri Court of Appeals has said:

> The whole idea of AAOs is to defer a final decision on current extraordinary costs until a rate case is in order. At the rate case, the utility is allowed to make a case that the deferred costs should be included, but again there is no authority for the proposition put forth here that the PSC is bound by the AAO terms.[84]

B. The Commission's decision to grant the AAO is not based on the same standard it now must use to determine whether those costs should be recovered. In granting the AAO, the Commission only determined that uncollected revenue was an item that could be deferred under accounting standards and that Ameren Missouri's loss was extraordinary and material.[85] But now, in this rate case, the Commission must consider "all relevant factors," otherwise it would be engaging in impermissible single-issue

[81] File Nos. ER-2010-0036 and ER-2012-0166

[82] Meyer Direct, Ex. 513, Page 16, Lines 12-13.

[83] *State ex rel. Missouri Gas Energy v. Public Serv. Com'n*, 210 S.W.3d 330 (Mo. App. W.D. 2006)

[84] *Missouri Gas Energy v. Public Serv. Com'n*, 978 S.W.2d 434, 438 (Mo. App. W.D. 1998).

[85] *In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for the Issuance of an Accounting Authority Order Relating to its Electrical Operations*, Report and Order, File No. EU-2012-0027, November 26, 2013.

ratemaking.[86]

C. Staff, Public Counsel, and MIEC argue that Ameren Missouri's attempt to recover what it calls unrecovered fixed costs and what the opposing parties call unrecovered revenues or lost profit, constitutes an attempt at forbidden retroactive ratemaking. In arguing that recovery should not be allowed, the opposing parties point to a decision of the Missouri Supreme Court in *State ex rel. Utility Consumers Council of Missouri, Inc.,*[87] a decision that is frequently referred to as simply "*UCCM*" .

D. In *UCCM*, the Supreme Court struck down a Commission decision that allowed electric utilities to implement a fuel adjustment clause without supporting statutory authority. Having declared that the fuel adjustment clause was impermissible, the Supreme Court considered the legality allowing the electric utilities to collect a surcharge from customers to recover fuel costs from ratepayers for a period between the time an earlier fuel adjustment clause expired and before the challenged FAC went into effect. In refusing to allow the utilities to keep the money collected under the surcharge, the Court said:

> The utilities take the risk that rates filed by them will be inadequate or excessive, each time they seek rate approval. To permit them to collect additional amounts simply because they had additional past expenses not covered by either clause is retroactive rate making, i.e. the setting of rates which permit a utility to recover past losses or which require it to refund past excess profits collected under a rate that did not perfectly match expenses plus rate-of-return with the rate actually established.[88]

The Court then went on to find that the surcharge allowed the utilities to collect monies not collectible under the rate filed at the time the expenses were incurred, and the utilities had

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[86] *State ex rel. Missouri Gas Energy v. Public Serv. Com'n*, 210 S.W.3d 330 (Mo. App. W.D. 2006)

[87] 585 S.W.2d 41 (Mo banc 1979).

[88] *State ex rel. Utility Consumers Council of Missouri, Inc. v. Pub. Serv. Com'n*, 585 S.W.2d 41, 59, (Mo banc 1979).

no vested right to keep the money.

E. Although the quoted language from *UCCM* is quite broad, the Court's actual holding is more narrow. In fact, earlier in its discussion of those costs, the Supreme Court hints that if the expenses in question had been "'current' expenses reasonably anticipated and intended under the old clause, to be recovered at some point and were simply uncollected 'revenues'", they might have been recoverable.[89]

F. Certainly, in subsequent appellate decisions, the Court of Appeals has been open to the idea of allowing deferred costs to be recovered through a subsequent rate case. For example, in a 1998 case concerning legality of the Purchase Gas Adjustment (PGA) established in the tariffs of Missouri's natural gas distribution companies, the Court of Appeals held that the PGA was not improper retroactive ratemaking of the sort disapproved by the Supreme Court in *UCCM* because the rate adjustments made under the PGA are applied only to future customers on future bills.[90]

G. Similarly, in considering an appeal of an earlier Ameren Missouri rate case, the Court of Appeals held that the future amortized recovery of costs deferred under the vegetation management tracker did not constitute retroactive rate making.[91]

Decision:

As explained in its Conclusions of Law, the Commission must now evaluate all relevant factors to determine whether it is appropriate to allow Ameren Missouri to

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[89] *State ex rel. Utility Consumers Council of Missouri, Inc. v. Pub. Serv. Com'n*, 585 S.W.2d 41, 59, (Mo banc 1979).

[90] *State ex rel. Midwest Gas Users' Ass'n v. Pub. Serv. Com'n*, 976 S.W.2d 470, 481 (Mo. App. W.D. 1998).

[91] *State ex rel. Noranda Aluminum, Inc. v. Pub. Serv. Com'n* 356 S.W.3d 293, 319 (Mo. App. S.D. 2011).

recover the deferred unrecovered fixed costs in the rates that will be established in this case.

Ameren Missouri faced this problem of uncollected revenues because of the fuel adjustment clause through which it sought to reduce its risk from increasing net energy costs. If the fuel adjustment clause had not been in place following the 2009 ice storm and the resulting disruption to Noranda's production, Ameren Missouri could have recovered its fixed costs by the means it originally attempted, by selling the additional available power off-system. Unfortunately for the company, the fuel adjustment clause operated, as intended, and swept up 95 percent of those sales to be netted against rising energy costs, thereby reducing any cost recovery that would have occurred through the fuel adjustment clause. Thus, the fuel adjustment clause, from which the company expected to benefit, instead worked to the benefit of ratepayers.

Ameren Missouri did not foresee that result when the fuel adjustment clause was approved, but it is neither unjust nor unreasonable. When Ameren Missouri chose to provide service to a customer the size of Noranda, it understood that the profits it could earn from the business relationship came with a substantial risk. The risk that Noranda's production would fall and that it would be unable to sell as much electricity as it anticipated was a risk the company's shareholders, who benefit from the profits earned by serving Noranda, should bear. Ratepayers are not the insurers of Ameren Missouri's profits and should not have to bear the risk that those profits are not as great as anticipated because of a drop in production at Noranda. To now alter the consequences of that drop in production would be to retroactively change the allocation of risk approved by the Commission for the fuel adjustment clause that was in effect at the time.

In addition to this concern, the AAO granting deferral of these costs is unique in that Ameren Missouri has pursued and been granted a rate increase between this case and the losses at issue in this AAO. In that rate case, all relevant factors were considered, and rates for the future were set based on a period of time. It is not preferable to set rates in this case based on losses that are separated from the current test year by a number of years and by an intervening rate case.

Finally, Ameren Missouri experienced more than sufficient earnings to cover its fixed costs during all time periods between the ice storm and this rate case. While not a determinative factor alone in deciding whether to grant recovery of any AAO, this is one of the relevant factors the Commission must consider in setting just and reasonable rates in this case.

After considering all relevant factors, the Commission decides that recovery of the amounts deferred under the previously established accounting authority order is not appropriate.

6. Storm Expense and Two-Way Storm Costs Tracker

A. Should the Commission continue a two-way storm restoration cost tracker whereby storm-related non-labor operations and maintenance ("O&M") expenses for major storms would be tracked against the base amount with expenditures below the base creating a regulatory liability and expenditures above the base creating a regulatory asset, in each case along with interest at the Company's AFUDC rate?

Findings of Fact:

1. In Ameren Missouri's last rate case, the Commission established a two-way tracker for recovery of major storm related non-labor operations and maintenance expenses that would be tracked around a base level. If costs exceeded the base level, Ameren Missouri would be allowed to defer them for future recovery. If costs fell below the base level, Ameren Missouri would return the difference to ratepayers in a future rate case.[92]

2. In establishing the major storm cost tracker in the last rate case, the Commission expressed general skepticism of proposed tracking mechanisms, and noted there is a legitimate concern that a tracker can reduce a company's incentive to aggressively control costs. At that time, the Commission believed that those concerns were outweighed by the benefits of the two-way tracker.[93]

3. Ameren Missouri contends the tracker has worked as anticipated and asks that it be continued in this case.[94] Staff, Public Counsel, and MIEC all oppose continuation of the tracker.

4. Standard ratemaking methods already exist apart from the tracker to address these non-labor operations and maintenance major storm costs without the need for a tracker. The standard practice is to establish an average amount of storm costs to be included in rates to cover the company's costs. If the actually incurred costs are less than that amount, the company gets to keep the difference. If the actually incurred costs are

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[92] Boateng Rebuttal, Ex. 205, Page 3, Lines 17-26.

[93] *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service,* File No. ER-2012-0166, Report and Order, December 12, 2012, Page 96, Finding of Fact 11.

[94] Wakeman Rebuttal, Ex. 46, Page 4, Lines 7-17.

more than that amount, the company is at risk of suffering a shortfall. But if an extraordinary storm event occurs between rate cases, the company can request an accounting authority order to defer those extraordinary costs for possible inclusion in rates in a subsequent rate case.[95]

5. Using this combination of methods, before the tracker was implemented, Ameren Missouri was able to recover every dollar of expenses incurred for storm restorations between April 1, 2007, and September 30, 2014.[96]

6. Major storm costs are only a small part of Ameren Missouri's overall costs. During the test year, Ameren Missouri experienced approximately $6.8 million of non-labor storm restoration costs in comparison to approximately $2.6 billion of total operating expenses. That means the storm restoration costs are only 0.0026 percent of the company's total operating expenses.[97]

7. None of the other investor-owned electric utilities in Missouri have a storm restoration cost tracker.[98]

8. By their nature, cost trackers tend to reduce a utility's incentive to aggressively control costs by ensuring that all costs will be recovered.[99] Under a tracker, such costs would be subject to a prudence review, but a prudence review cannot control costs as efficiently as a strong economic incentive. Ameren Missouri obviously cannot control when its service area may be hit by a major storm, but it has at least some control

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[95] Boateng Rebuttal, Ex. 205, Pages 4-5, Lines 12-22, 1-2.

[96] Boateng Rebuttal, Ex. 205, Page 8, Lines 11-13.

[97] Boateng Rebuttal, Ex. 205, Page 9, Lines 4-14.

[98] Boateng Rebuttal, Ex. 205, Page 10, Lines 19-23.

[99] Transcript, Page 853, Lines 9-12.

over how it spends money in response to such storms.[100]

9. Ameren Missouri indicates it will continue to provide prompt and efficient storm restoration services with or without a tracker,[101] and there have been no allegations that it has not provided good storm restoration services in the past. Nevertheless, good public policy still requires the extra incentive a utility faces without the protection of a tracker.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

Storm costs have been shown to be relatively small and predictable. An exception to traditional ratemaking is not necessary to recover those costs. The Commission finds that eliminating the major storms cost tracker is good public policy.

B. If the storm cost tracker is not continued, what annualized level of major storm costs should the Commission approve in this case?

Findings of Fact:

1. With the major storm cost tracker having been eliminated, the Commission must now determine the amount of anticipated costs to be included in Ameren Missouri's rates. All parties agree the amount of major storm costs to be included in rates is $4.6 million, which is based on a 60-month normalization of such costs.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

[100] Robertson Surrebuttal, Ex. 408, Page 9, Lines 2-14. See also, Boateng Surrebuttal, Ex. 206, Page 5, Lines 6-23. .

[101] Transcript, Page 843, Lines 13-23.

Decision:

The Commission accepts the recommendation of the parties and will set the amount of major storm costs to be included in rates at $4.6 million.

C. Should an amount of major storm cost over-recovery by Ameren Missouri be included in Ameren Missouri's revenue requirement and, if so, over what period should it be amortized?

Findings of Fact:

1. During the test year, Ameren Missouri spent less on major storm restoration costs than the base amount that was included in the tracker. All parties agree the amount of over-recovery should be returned to ratepayers.

2. Public Counsel recommends the over-recovery be returned to ratepayers amortized over two years. Staff and Ameren Missouri recommend the over-recovery be amortized and returned over five years, which is the length of time generally used for such amortizations.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The Commission finds that a five year amortization is appropriate as that is the length of time that has generally been used for storm expense amortizations.

7. Vegetation Management and Infrastructure Inspection Trackers

B. Should the vegetation management and infrastructure inspection trackers be continued?[102]

[102] For the sake of clarity, the Commission is addressing sub-issue B before sub-issue A.

Findings of Fact:

1. Ameren Missouri's vegetation management and infrastructure inspection expense is closely associated with two Commission rules. Following extensive storm related service outages in 2006, the Commission promulgated new rules designed to compel Missouri's electric utilities to do a better job of maintaining their electric distribution systems. Those rules, entitled Electrical Corporation Infrastructure Standards[103] and Electrical Corporation Vegetation Management Standards and Reporting Requirements,[104] became effective on June 30, 2008.

2. The rules establish specific standards requiring electric utilities to inspect and replace old and damaged infrastructure, such as poles and transformers. In addition, electric utilities are required to more aggressively trim tree branches and other vegetation that encroaches on transmission lines. In promulgating the stricter standards, the Commission anticipated utilities would have to spend more money to comply. Therefore, both rules include provisions that allow a utility the means to recover the extra costs it incurs to comply with the requirements of the rule.

3. In an earlier rate case, ER-2008-0318,[105] the Commission allowed Ameren Missouri to recover a set amount in its base rates for vegetation management and infrastructure inspection costs. However, since the rules were new, the Commission found that Ameren Missouri had too little experience to know how much it would need to spend to comply with the vegetation management and infrastructure inspection rules. Because of

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[103] Commission Rule 4 CSR 240-23.020.

[104] Commission Rule 4 CSR 240-23.030.

[105] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, 18 Mo. P.S.C. 3d 306 (2009).

that uncertainty, the Commission established a two-way tracking mechanism to allow Ameren Missouri to track its vegetation management and infrastructure costs.

4. The order required Ameren Missouri to track actual expenditures over and under the base level. In any year in which Ameren Missouri spent below that base level, a regulatory liability would be created. In any year in which Ameren Missouri's spending exceeded the base level, a regulatory asset would be created. The regulatory assets and liabilities would be netted against each other and would be considered in a future rate case. The tracking mechanism contained a 10 percent cap so if Ameren Missouri's expenditures exceeded the base level by more than 10 percent it could not defer those costs under the tracking mechanism, but would need to apply for an additional accounting authority order. The Commission's order indicated the tracking mechanism would operate until new rates were established in Ameren Missouri's next rate case.[106]

5. The Commission renewed the tracking mechanism in Ameren Missouri's next three rate cases, ER-2010-0036, ER-2011-0028, and ER-2012-0166, finding that Ameren Missouri's costs to comply with the vegetation management and infrastructure inspection rules were still uncertain, as the company had not yet completed a full four/six year vegetation management cycle on its entire system. But in each case, the Commission indicated it did not intend to make the tracker permanent.[107]

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[106] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, 18 Mo. P.S.C. 3d 306, 339 (2009).

[107] *In the Matter of Union Electric Company, d/b/a Ameren UE's Tariffs to Increase its Annual Revenues for Electric Service, Report and Order*, File No. ER-2010-0036, 19 Mo. P.S.C. 3d 376 (2010); *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service,* Report and Order, File No. ER-2011-0028, July 13, 2011; and *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service,* Report and Order, File No. ER-2012-0166, December 12, 2012.

6. Ameren Missouri asks that the tracker be continued. Staff, Public Counsel, MIEC, and MECG contend the tracker is no longer necessary and urge the Commission to end it.

7. Ameren Missouri has been operating under the Commission's vegetation management and infrastructure inspection rules for over seven years and has completed its first four-year cycle for vegetation management work on urban circuits and its first six-year cycle of work on rural circuits under the requirements of the rules.[108]

8. Tracker mechanisms can be a useful regulatory tool in the correct circumstances, but they should be used sparingly because they can reduce the incentive of the utility to closely control its costs.[109]

Conclusions of Law:

A. Commission Rule 4 CSR 240-23.020 establishes standards requiring electrical corporations, including Ameren Missouri, to inspect its transmission and distribution facilities as necessary to provide safe and adequate service to its customers. Specifically, 4 CSR 240-23.020(3)(A) establishes a four-year cycle for inspection of urban infrastructure and a six-year cycle for inspection of rural infrastructure.

B. Commission Rule 4 CSR 240-23.020(4) establishes a procedure by which an electric utility may recover expenses it incurs because of the rule. Specifically, that section states as follows:

> In the event an electrical corporation incurs expenses as a result of this rule in excess of the costs included in current rates, the corporation may submit a request to the commission for accounting authorization to defer recognition and possible recovery of these excess expenses until the effective date of rates resulting from its next general rate case, filed after the

[108] Staff Report Revenue Requirement, Ex. 202, Page 110, Lines 15-18.

[109] Robertson Direct, Ex. 406, Pages 20-21, Lines 22-18, 1-10.

> effective date of this rule, using a tracking mechanism to record the difference between the actually incurred expenses as a result of this rule and the amount included in the corporation's rates … In the event that such authorization is granted, the next general rate case must be filed no later than five (5) years after the effective date of this rule. …

Ameren Missouri points to the mention of a tracking mechanism in this regulation to argue that the regulation recognizes the appropriateness of a tracker for the recovery of these costs. However, when read in context, it is clear that the tracker mentioned in the rule is intended to deal with the uncertainty of the cost of compliance with the new rule. The Commission established a tracker for just that purpose, but now the costs are well known and the tracker is no longer needed.

C. Commission Rule 4 CSR 240-23.030 establishes standards requiring electrical corporations, including Ameren Missouri, to trim trees and otherwise manage the growth of vegetation around its transmission and distribution facilities as necessary to provide safe and adequate service to its customers. Specifically, 4 CSR 240-23.030(9) establishes a four-year cycle for vegetation management of urban infrastructure and a six-year cycle for vegetation management of rural infrastructure. The vegetation management rule also includes a provision that allows Ameren Missouri to ask the Commission for authority to accumulate and recover its cost of compliance in its next rate case.[110]

Decision:

From the time this tracker was created, the Commission has said that it would only be a temporary expedient, needed only until a sufficient cost history could develop to allow for the accurate determination of normalized costs. A sufficient cost history now exists and the need for the tracker is at an end. The Commission finds that the vegetation

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[110] Commission Rule 4 CSR 240-23.030(10).

management and the infrastructure inspection tracker are discontinued.

A. What amount should be included in the revenue requirement for Vegetation Management and Infrastructure Inspection?

C. If the vegetation management and infrastructure inspection trackers are not continued, what annualized level of vegetation management and infrastructure inspection costs should the Commission approve in this case?

Findings of Fact:

1. With the tracker having been eliminated, the Commission now must carefully establish the amount that Ameren Missouri may recover in its base rates for its vegetation management and infrastructure inspection costs.

2. Ameren Missouri proposes that the base rate level for vegetation management costs be set at approximately $56 million, with the base rate level for infrastructure inspections costs set at approximately $6.4 million. Those numbers are the actual incurred amount of costs through the true-up period.[111]

3. Staff proposes to use a three-year average of expenses to set the base rate cost level for vegetation management at $54,504,662 and $5,827,267 for infrastructure inspections.[112]

4. MIEC proposed a vegetation management cost level of $54 million, with $5.8 million allowed for infrastructure inspections.[113]

5. Public Counsel proposes to use a 62-months average covering the period of February 2009, through March 2014, adjusted for the true-up figures through December 31, 2014, to set the base level at $53,114,501 for vegetation management. Public Counsel

[111] Moore Surrebuttal, Ex. 32, Page 9, Lines 5-11.

[112] Hanneken Surrebuttal, Ex. 218, Page 9, Lines 8-12.

[113] Meyer Surrebuttal, Ex. 514, Page 20, Lines 8-11.

used a two-year average, adjusted for true-up figures to set the base level at $6,149,077 for infrastructure inspections.[114]

6. This is a chart of Ameren Missouri's annual vegetation management costs since 2008:

2008	$49.2 million
2009	$50.9 million
2010	$50.4 million
2011	$52.9 million
2012	$52.3 million
2013	$55.2 million[115]
2014	$56.0 million[116]

The chart shows some up and down variation from year to year, but it also shows a definite upward trend. An average of all years of cost as proposed by Public Counsel and MIEC would not be a good representation of future costs since it would not recognize the upward trend. On the other hand, Ameren Missouri's proposal to just use the updated test year amounts is also not reasonable because it fails to recognize that the costs do not increase in a straight line. Staff's three-year average recognizes both aspects of the cost trend and is the most reasonable.

7. In the first year that Ameren Missouri incurred infrastructure inspection costs, 2008, the Company incurred annual infrastructure inspection costs of $8,165,926. By the fourth year, 2011, those annual costs had dropped to $5,373,259. For the test year ending March 31, 2014, the costs were $5,924, 356. On that basis, Public Counsel recommended that the base cost be set at the average of the last two twelve-month periods ending March

[114] Robertson True-Up Direct, Ex. 413, Page 2, Lines 5-18.

[115] Meyer Direct Ex. 513, Page 18, Table 3.

[116] Moore Surrebuttal, Ex. 32, Page 9, Lines 5-11.

2013 and 2014.[117] In the update period those costs had risen to approximately $6.4 million.[118] In True-Up Direct testimony, Public Counsel updated its proposed amount to include the update period ending December 31, 2014. The two-year average, utilizing the twelve months ended December 2013 and 2014 is $6,149,077. Public Counsel recommends the infrastructure inspection amount included in base rates be set at that amount.[119]

Conclusions of Law:

The Commission makes no additional conclusions of law on this issue.

Decision:

The Commission establishes the base rate cost level for vegetation management at $54,504,662, which is the number recommended by Staff. The base rate cost level for infrastructure inspections is established at $6,149,077, the number recommended by Public Counsel. The Commission finds that the two-year average number recommended by Public Counsel appropriately captures the recent increases in costs while assuring that the increased expense numbers from the true-up period are not just an anomaly.

D. Should an amount of vegetation management and infrastructure inspection cost over-recovery by Ameren Missouri be included in Ameren Missouri's revenue requirement and, if so, over what period should they be amortized?

Findings of Fact:

1. Since the last rate case, the vegetation management half of the tracker resulted in a regulatory asset, meaning Ameren Missouri spent more for vegetation management than the base level established in the tracker. The infrastructure inspection

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[117] Robertson Surrebuttal, Ex. 408, Page 14, Lines 4-17.

[118] Moore Surrebuttal, Ex. 32, Page 9, Lines 8-11.

[119] Robertson True-Up Direct, Ex. 413, Page 2, Line 5-18.

half of the tracker resulted in a regulatory liability, meaning Ameren Missouri spent less than the base amount established in the tracker. Under the terms of the tracker the two items are to be netted against each other and the resulting amount recovered from or returned to ratepayers. In addition, some amounts from the tracker ordered to be amortized in previous rate cases remain uncollected.[120] Staff, Public Counsel, and Ameren Missouri propose to combine all three figures and amortize that amount to be collected from ratepayers.

2. According to Staff's calculations, including true-up data, the revised total amount to be amortized and collected from ratepayers is $1,539,810. Amortized over three years as Staff and Ameren Missouri propose, that amounts to an annual figure of $513,270.[121]

3. Public Counsel proposed that the net over/under recovery amount be amortized over two years.[122]

4. The Commission has used a three-year amortization for tracked vegetation management and infrastructure inspection expenses in all previous Ameren Missouri rate cases in which the tracker was in place.[123]

5. MIEC opposes any collection of the regulatory asset resulting from under collections under the tracker because of its contention that Ameren Missouri over-earned during the period covered by the tracker.[124]

Conclusions of Law:

The Commission makes no additional conclusions of law on this issue.

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[120] Staff Report Revenue Requirement, Ex. 202, Page 110, Lines 4-31.

[121] Hanneken Surrebuttal, Ex. 218, Page 10, Lines 5-8.

[122] Robertson Direct, Ex. 406, Page 27, Lines 19-23.

[123] Staff Report Revenue Requirement, Ex. 202, Page 110, Lines 9-10.

[124] Meyer Direct, Ex. 513, Page 20, Lines 8-13.

Decision:

Staff has established the appropriate amount of the under-recovery in the existing tracker and the Commission finds that Staff's recommended amount shall be recovered from ratepayers amortized over three years.

8. Union Proposals

A. Can the Commission mandate or require that the Company address its workforce needs in a particular manner and, if so, should it do so?

Findings of Fact:

1. This issue is raised by the International Brotherhood of Electrical Workers Local 1439, AFL-CIO. That local represents 703 members who work for Ameren Missouri. Local 1439 does not represent all unionized Ameren Missouri employees; some are represented by other locals or other unions.[125] For convenience, this report and order will refer to Local 1439 simply as the "Union."

2. The Union affirms that Ameren Missouri has been providing its customers with "consistently reliable and inexpensive power for decades."[126] But it is concerned about what it describes as an aging workforce and an aging infrastructure.

3. To address the aging workforce problem, to replace current employees who are moving toward retirement, the Union asks the Commission to allocate an extra $11.1 million to Ameren Missouri and require the company to use that extra money to induct a class of at least 37 apprentices in various job categories in 2015 and for the next two successive years. Further, the Union asks the Commission to demand that Ameren Missouri fill all jobs, internal or outsourced, first within its service territory, second in

[125] Walter Direct, Ex. 800, Page 2, Lines 1-17.

[126] Walter Direct, Ex. 800, Page 3, Lines 29-30.

Missouri, and never offshore[127]

4. The Union also expresses concern that Ameren Missouri is using too much contract labor rather than hiring additional internal workers because it believes the quality of the work provided by its members is superior to that provided by contract employees.[128] The Union's witness conceded there was no way to quantify that belief.[129]

5. Ameren Missouri has decreased the number of internal employees in recent years to improve efficiency and reduce costs.[130] But the company has completed all mandatory and scheduled maintenance work.[131] There is no evidence to suggest these reductions have prevented the company from offering safe and adequate service to its customers.

6. Ameren Missouri uses some contract labor to ensure efficient and effective completion of its work, particularly to meet short-term needs.[132] The company uses contract labor to do special projects that temporarily require a larger workforce. It would not be cost-effective to hire permanent employees to do that work if they would have to be laid-off when the special project was finished.[133]

7. Ameren Missouri is already planning to hire all the internal apprentices it believes it needs, and it does not want a special allocation for that purpose.[134]

8. The Union asks the Commission to address the aging infrastructure problem

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[127] Walter Direct, Ex. 800, Page 9, Lines 16-23.

[128] Transcript, Pages 1040-1041, Lines 6-25, 1-11, and Ex. 801.

[129] Transcript, Page 1041, Lines 12-15.

[130] Wakeman Rebuttal, Ex. 46, Page 12, Lines 8-22.

[131] Wakeman Rebuttal, Ex. 46, Page 13, Lines 5-9.

[132] Wakeman Rebuttal, Ex. 46, Page 13, Lines 11-15.

[133] Transcript Pages 987-988, Lines 25, 1-23.

[134] Transcript, Pages 1015-1016, Lines 16-25, 1-10.

by giving the company an undefined special annual rate allocation in an undefined amount to allow the company to address its infrastructure needs.[135]

9. The Union's witness did not suggest any particular way the Commission might help Ameren Missouri meet its infrastructure needs, but in its brief, the Union suggested the Commission create a pool of money to allow the company to quickly be reimbursed for infrastructure expenditures or create an infrastructure system replacement surcharge such as authorized for other Missouri utilities.[136]

Conclusions of Law:

A. Section 393.130.1, RSMo (Cum. Supp. 2013), requires every electrical corporation, including Ameren Missouri, to "furnish and provide such service instrumentalities and facilities as shall be safe and adequate and in all respects just and reasonable."

B. Section 393.140.(1) gives this Commission general supervisory authority over all electrical corporations, again including Ameren Missouri. Subsection (2) of that statute authorizes the Commission to examine or investigate the operations of such utilities and to:

> order such reasonable improvements as will promote the public interest, preserve the public health and protect those using such … electricity …., and those employed in the manufacture and distribution thereof, and have power to order reasonable improvements and extensions of the works, wires, poles, pipes, lines, conduits, ducts and other reasonable devices, apparatus and property of … electrical corporations … .

Based on the authority given by that statute, the Commission may exercise a great deal of control over Ameren Missouri's operations.

[135] Walter Direct, Ex. 800, Pages 9-10, Lines 31, 1-3.

[136] IBEW 1439's Post-Hearing Brief, Page 3, Fn. 1

C. But, while the Commission has authority to regulate Ameren Missouri to ensure the utility provides safe and adequate service, the Commission does not have authority to manage the company. In the words of the Missouri Court of Appeals;

> The powers of regulation delegated to the Commission are comprehensive and extend to every conceivable source of corporate malfeasance. Those powers do not, however, clothe the Commission with the general power of management incident to ownership. The utility retains the lawful right to manage its own affairs and conduct its business as it may choose, as long as it performs its legal duty, complies with lawful regulation, and does no harm to public welfare.[137]

Therefore, except as necessary to ensure the provision of safe and adequate service, the Commission does not have the authority to dictate to the company how many employees it must hire or whether it must use internal workforce rather than outside contractors to perform the work of the company.

D. The Commission's authority to assist Ameren Missouri in its efforts to direct capital expenditures toward aging infrastructure is also limited by statute. Section 393.135, RSMo 2000, prohibits the recovery in electric rates of the cost of construction work in progress or CWIP. That means Ameren Missouri cannot charge its customers to develop a fund to allow for quick recovery of the cost of unfinished capital projects. Similarly, the infrastructure system replacement surcharges that the Commission has established for water and gas utilities in Missouri are authorized by statute. No similar statutory authority exists for the creation of an ISRS for electric utilities.

Decision:

The evidence presented by the Union does not demonstrate that Ameren Missouri has failed to provide safe and adequate service. Therefore, the Commission will not

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[137] *State ex rel. Harline v. Public Serv. Com'n*, 343 S.W.2d 177, 182 (Mo. App. 1960)

dictate to the company how many new employees it must hire, nor will it determine whether it must use its internal workforce or outside contractors to perform the company's work. Furthermore, there is no need for the Commission to direct Ameren Missouri to undertake any particular infrastructure replacement projects at this time.

B. Should the Commission require the additional reporting requested by Mr. Walters?

Findings of Fact:

1. The Union proposes that Ameren Missouri be required to provide additional quarterly reports to the Commission's Staff regarding its spending for infrastructure replacement and related to the special allocations proposed in the previous sub-issue.[138]

2. Ameren Missouri is ready to provide any information that Staff may request from it and believes that no additional reporting requirement is needed.[139]

Conclusions of Law:

The Commission makes no additional conclusions of law on this issue.

Decision:

The Commission finds there is no need to impose a new reporting requirement on Ameren Missouri as Staff can already obtain whatever information it needs from Ameren Missouri. Further, additional reporting requirements would ultimately increase costs for Ameren Missouri's ratepayers.

9. Return on Common Equity ("ROE")

In consideration of all relevant factors, what is the appropriate value for Return on Equity ("ROE") that the Commission should use in setting Ameren Missouri's Rate of Return?

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[138] Walter Direct, Ex. 800, Page 9, Lines 25-31.

[139] Transcript, Page 1015, Lines 7-15.

Findings of Fact:

1. This issue concerns the rate of return Ameren Missouri will be authorized to earn on its rate base. Rate base is the value of the utility's assets such as generating plants, electric meters, wires and poles, and the trucks driven by Ameren Missouri's repair crews. In order to determine a rate of return, the Commission must determine Ameren Missouri's cost of obtaining the capital it needs.

2. The relative mixture of sources Ameren Missouri uses to obtain the capital it needs is its capital structure. Ameren Missouri's actual capital structure as of the true-up date, December 31, 2014 is:

Long-Term Debt	47.18%
Short-Term Debt	00.00%
Preferred Stock	01.07%
Common Equity	51.76%[140]

No party has raised an issue regarding capital structure, so the Commission will not further address this matter.

3. Similarly, no party has raised an issue regarding Ameren Missouri's calculation of the cost of its long-term debt and preferred stock.

4. Determining an appropriate return on equity is the most difficult part of determining a rate of return. The cost of long-term debt and the cost of preferred stock are relatively easy to determine because their rate of return is specified within the instruments that create them. In contrast, to determine a return on equity, the Commission must consider the expectations and requirements of investors when they choose to invest their money in Ameren Missouri rather than in some other investment opportunity. As a result, the Commission cannot simply find a rate of return on equity that is unassailably

[140] Murray Surrebuttal, Ex. 228, Page 4, Line 12.

scientifically, mathematically, or legally correct. Such a "correct" rate does not exist. Instead, the Commission must use its judgment to establish a rate of return on equity attractive enough to investors to allow the utility to fairly compete for the investors' dollar in the capital market without permitting an excessive rate of return on equity that would drive up rates for Ameren Missouri's ratepayers. To obtain guidance about the appropriate rate of return on equity, the Commission considers the testimony of expert witnesses.

5. Four financial analysts offered recommendations regarding an appropriate return on equity in this case. Robert B. Hevert testified on behalf of Ameren Missouri. Hevert is Managing Partner of Sussex Economic Advisors, LLC. He holds a Bachelor of Science degree in Finance from the University of Delaware and a Master of Business Administration with a concentration in finance from the University of Massachusetts.[141] He recommends the Commission allow Ameren Missouri a return on equity of 10.4 percent, within a range of 10.2 percent to 10.6 percent.[142]

6. Michael Gorman testified on behalf of MIEC. Gorman is a consultant in the field of public utility regulation and is a managing principal of Brubaker & Associates.[143] He holds a Bachelor of Science degree in Electrical Engineering from Southern Illinois University and a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield.[144] Gorman recommends the

[141] Hevert Direct, Ex. 16, Page 1, Lines 5-16.
[142] Hevert Direct, Ex. 16, Page 2, Lines 16-21.
[143] Gorman Direct, Ex. 510, Page 1, Lines 4-6.
[144] Gorman Direct, Ex. 510, Appendix A, Page 1, Lines 9-12.

Commission allow Ameren Missouri a return on equity of 9.30 percent, within a recommended range of 9.00 percent to 9.60 percent.[145]

7. Lance Schafer testified on behalf of the Public Counsel. Schafer is employed by the Office of the Public Counsel as a Public Utility Financial Analyst. He holds a Bachelor of Arts in English from the University of Missouri, Columbia; a Master of Arts in French from the University of California, Irvine; and a Master of Business Administration with a specialization in Finance from the University of Missouri, Columbia.[146]

8. Finally, David Murray testified on behalf of Staff. Murray is the Utility Regulatory Manager of the Financial Analysis Unit for the Commission. He holds a Bachelor of Science degree in Business Administration from the University of Missouri – Columbia, and a Masters degree in Business Administration from Lincoln University. Murray has been employed by the Commission since 2000 and has offered testimony in many cases before the Commission.[147] Murray recommends a return on equity of 9.25 percent, within a range of 9.00 percent to 9.50 percent.[148]

9. A utility's cost of common equity is the return investors require on an investment in that company. Investors expect to achieve their return by receiving dividends and through stock price appreciation.[149] To comply with standards established by the United States Supreme Court, the Commission must authorize a return on equity sufficient

[145] Gorman Direct, Ex. 510, Page 2, Lines 4-9.

[146] Schafer Direct, Ex. 409, Page 1, Lines 11-15.

[147] Staff Report Revenue Requirement Cost of Service, Ex. 202, Appendix 1, Page 61.

[148] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 11, Lines 1-11.

[149] Gorman Direct, Ex. 510, Page 11, Lines 17-19.

to maintain financial integrity, attract capital under reasonable terms, and be commensurate with returns investors could earn by investing in other enterprises of comparable risk.[150]

10. Financial analysts use variations on three generally accepted methods to estimate a company's fair rate of return on equity. The Discounted Cash Flow (DCF) method is based on a theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the Constant Growth DCF model expresses the Cost of Equity as the discount rate that sets the current price equal to expected cash flows.[151] The analysts also use variations of the DCF model including the multi-stage growth DCF[152] and the sustainable growth DCF[153] The Risk Premium method assumes that the investor's required return on an equity investment is equal to the interest rate on a long-term bond plus an additional equity risk premium needed to compensate the investor for the additional risk of investing in equities compared to bonds.[154] The Capital Asset Pricing Method (CAPM) assumes the investor's required rate of return on equity is equal to a risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.[155] No one method is any more "correct" than any other method in all circumstances. Analysts balance their use of all three methods to reach a recommended return on equity.

11. Before examining the analyst's use of these various methods to arrive at a recommended return on equity, it is important to look at some other numbers. For 2014,

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[150] Gorman Direct, Ex. 510, Page 12, Lines 1-11.

[151] Hevert Direct, Ex. 16, Page 14, Lines 5-8.

[152] Hevert Direct, Ex. 16, Page 19, Lines 7-14.

[153] Gorman Direct, Ex. 510, Pages 19-20

[154] Hevert Direct, Ex. 16, Page 28, Lines 4-14.

[155] Gorman Direct, Ex. 510, Pages 32-33, Lines 13-24, 1-13.

the average return on equity awarded to all electric utilities by state commissions in this country was 9.76 percent. For fully litigated rate cases, the average number dropped to 9.63 percent. But those numbers include distribution only companies in deregulated states. Excluding those companies and looking only at vertically integrated electric companies like Ameren Missouri, the average return on equity award in 2014 was 9.94 percent. Looking only at returns established in fully litigated rate cases, that average was 9.86 percent.[156]

12. The Commission mentions the average allowed return on equity because Ameren Missouri must compete with other utilities all over the country for the same capital. Therefore, the average allowed return on equity provides a reasonableness test for the recommendations offered by the return on equity experts.

13. In its decision regarding Ameren Missouri's last rate case, the Commission established an ROE of 9.8 percent.[157] Since 2012, when that case was decided, interest rates have declined by approximately 37 basis points.[158] Furthermore, utility stock prices have increased and their dividend yields have gone down. This indicates that utilities' cost of capital has decreased because they need to sell fewer shares to generate the capital they need to support their investments.[159] As MIEC's witness, Michael Gorman, explained: "Because the price of stock has gone up and the other parameters of the stock have not significantly changed, that's a clear indication that investors have reduced their required

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[156] Gorman Surrebuttal, Ex. 512, Schedule MPG-SR-1.

[157] *In the Matter of Union Electric Company, d/b/a/ Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service,* File No. ER-2012-0166, Report and Order, December 12, 2012.

[158] Gorman Surrebuttal, Ex. 512, Page 7, Lines 1-2.

[159] Gorman Surrebuttal, Ex. 512, Page 7, Lines 7-10.

cost of capital which has bid up the stock price."[160] This suggests the ROE allowed to Ameren Missouri should also be decreased.

14. Similarly, Staff's witness, David Murray, believes that investor expectations for ROE have declined so that today investors would reasonably expect an ROE of 9.5 percent.[161]

15. Ameren Missouri's expert witness, Robert Hevert, supports an increased ROE at 10.4 percent. The Commission finds that such an ROE would be excessive. In large part, Hevert's ROE estimate is high because he based his multi-stage DCF analysis calculations on an optimistic nominal long-term GDP growth rate outlook of 5.71 percent.[162] As Gorman explains, that growth rate is substantially higher than consensus economists' forward-looking real GDP growth outlooks.[163] Adjusting Hevert's optimistic growth rate outlook to the consensus economist level reduces his multi-stage growth DCF return from 10.02 percent to 8.80 percent for his proxy group.[164]

16. Similarly, if Hevert's CAPM analysis is adjusted to use more reasonable projected returns on the market, that analysis would result in a range of 8.80 percent to 9.52 percent.[165]

17. Gorman, a reliable rate of return expert, recommends the Commission set ROE in a range between 9.0 percent and 9.6 percent. He recommended that the rate be set at the mid-point of that range, which is 9.3 percent, but he indicated that any rate within

[160] Transcript, Page 1269, Lines 6-10.

[161] Transcript, Page 1358, Lines 9-14.

[162] Hevert, Direct, Ex. 16, Pages 22-23, Lines 3-9, 1-10.

[163] Gorman Rebuttal, Ex. 511, Page 8, Lines 1-7.

[164] Gorman Rebuttal, Ex. 511, Page 10, Lines 10-13.

[165] Gorman Rebuttal, Ex. 511, Page 13, Lines 8-14.

his range would be reasonable and would be adequate to attract capital at reasonable terms, would be sufficient to ensure the company's financial integrity, and is commensurate with returns on investment in enterprises having corresponding risks.[166]

18. Public Counsel's witness, Lance Schafer, recommended an ROE of 9.01 percent, within a range of 8.74 percent to 9.22 percent. Aside from any technical criticism about Schafer's methodology, an ROE of 9.01 is too low because it is substantially below the average ROE awarded by other state commissions to similarly situated utilities. Obviously, this Commission is not bound to follow the lead of other commissions in setting an appropriate ROE. In fact, the ROE the Commission has found to be reasonable in this case is below the average. But the capital market in which Ameren Missouri must compete is competitive. An ROE set 80 to 100 basis point below the ROE set for similar electric utilities could limit the company's ability to attract capital and could violate the *Hope* and *Bluefield* standard described earlier in this order, which requires that rates be set at a level that will allow the utility a return on its investment comparable to that earned by other companies with "corresponding risks and uncertainties."[167]

Conclusions of Law:

A. In assessing the Commission's ability to use different methodologies to determine just and reasonable rates, the Missouri Court of Appeals has said:

> Because ratemaking is not an exact science, the utilization of different formulas is sometimes necessary. … The Supreme Court of Arkansas, in dealing with this issue, stated that there is no 'judicial mandate requiring the Commission to take the same approach to every rate application or even to consecutive applications by the same utility, when the commission in its expertise, determines that its previous methods are unsound or inappropriate

[166] Transcript, Page 1197, Lines 9-23.

[167] *Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 692 (1923).

> to the particular application' (quoting Southwestern Bell Telephone Company v. Arkansas Public Service Commission, 593 S.W. 2d 434 (Ark 1980).[168]

Furthermore,

> Not only can the Commission select its methodology in determining rates and make pragmatic adjustments called for by particular circumstances, but it also may adopt or reject any or all of any witnesses' testimony.[169]

B. In another case, the Court of Appeals recognized that the establishment of an appropriate rate of return is not a "precise science":

> While rate of return is the result of a straight forward mathematic calculation, the inputs, particularly regarding the cost of common equity, are not a matter of 'precise science,' because inferences must be made about the cost of equity, which involves an estimation of investor expectations. In other words, some amount of speculation is inherent in any ratemaking decision to the extent that it is based on capital structure, because such decisions are forward-looking and rely, in part, on the accuracy of financial and market forecasts.[170]

Decision:

Based on the competent and substantial evidence in the record, on its analysis of the expert testimony offered by the parties, and on its balancing of the interests of the company's ratepayers and shareholders, as fully explained in its findings of fact and conclusions of law, the Commission finds that 9.53 percent is a fair and reasonable return on equity for Ameren Missouri. That rate is within expert witness Gorman's range, and only slightly above expert witness Murray's recommended range. The Commission finds that

[168] *State ex rel. Assoc. Natural Gas Co. v. Public Service Commission,* 706 S.W. 2d 870, 880 (Mo. App. W.D. 1985).

[169] *State ex rel. Assoc. Natural Gas Co. v. Public Service Commission,* 706 S.W. 2d 870, 880 (Mo. App. W.D. 1985).

[170] *State ex rel. Missouri Gas Energy v. Public Service Commission*, 186 S.W.3d 376, 383 (Mo App. W.D. 2005).

this rate of return will allow Ameren Missouri to compete in the capital market for the funds needed to maintain its financial health.

10. Class Cost of Service, Revenue Allocation and Rate Design

A. What methodology should the Commission use to allocate generation fixed costs among customer classes?

B. How should the non-fuel, non-labor components of production, operation and maintenance expense be classified and allocated?

G. What methodology should the Commission use to allocate off-system sales revenues among customer classes?

I. *What methodology should the Commission use to allocate fuel and purchased power costs among customer classes?*

H. What methodology should the Commission use to allocate income tax expense among customer classes?

Findings of Fact:

1. After the Commission determines the amount of rate increase that is necessary, it must decide how that rate increase will be spread among Ameren Missouri's customer classes. The basic principle guiding that decision is that the customer class that causes a cost should pay that cost.

2. The Class Cost of Service and Rate Design issue is similar to the ROE issue in that the method used to arrive at a number is less important than the reasonableness of the final number. Ameren Missouri, Staff, MIEC, and Public Counsel performed class cost of service studies using different methods with some different inputs. Each study is designed to measure how much each of the different rate classes contributes to Ameren Missouri's total cost of service. Rates should then be set so that each rate class contributes enough revenue to pay its fair share of those costs. But the class cost of service studies should not be taken as a precise mathematical calculation of correct

rates.[171] Rather, the Commission must use its judgment to set just and reasonable rates for the various rate classes.

3. Ameren Missouri's and MIEC's experts use an Average and Excess (A&E) four non-coincident peak production allocator methodology. That methodology conceptually splits the electric system into an average component and an excess component. The average component is the amount of capacity needed to produce the required energy if it were taken at the same demand rate each hour. The excess component measures the difference between average demand and peak demand at four non-coincident peaks.[172] The Commission has accepted the reasonableness of this methodology in past Ameren Missouri rate cases.

4. Staff's expert relied on several Base, Intermediate and Peak (BIP) class cost of service studies. As the name implies, the BIP studies attempt to divide class contributions to costs into three categories rather than the two used in the A&E methods. Despite the conceptual differences, Staff's BIP studies reach the same general conclusions as the A&E methods used by Ameren Missouri's and MIEC's experts.[173]

5. The one outlier method is the Peak and Average (P&A) methodology used as an alternative method by Public Counsel. The Commission has rejected the P&A methodology in past rate cases and Public Counsel offered an alternative A&E study in recognition of that previous rejection.[174]

6. The weakness with the P&A methodology is that after dividing the average

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[171] Transcript, Page 3022, Lines 2-25.

[172] Brubaker Direct, Ex. 503, Pages 25-26, Lines 16-22, 1-7. See also, Davis Direct, Ex. 7.

[173] Staff Report Rate Design, Ex. 201, Page 8, Lines 3-9.

[174] Marke Direct, Ex. 403, Page 26, Lines 7-13.

and excess components, instead of allocating just the excess average demand to the cost-causing classes, it allocates the entire peak demand to the various classes. That has the effect of double counting the average demand and allocates more costs to large industrials that have a steady but high average demand that does not contribute as much to the system peaks. That method works to the benefit of the residential class whose usage varies more by time of day and time of year.[175]

7. Public Counsel does not propose to adjust rates for the classes based specifically on its P&A study, instead supporting the joint position described in the objected-to non-unanimous stipulation and agreement that all rate classes should be given the same percentage increase.[176]

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The Commission will once again reject Public Counsel's P&A study because it has the effect of double counting average demand. Also, because the results of the A&E and BIP studies are similar, the Commission does not need to decide which particular study is most appropriate. Therefore, all the specific sub-issues involving the difference between those studies are moot and do not need to be addressed in this case. The Commission will need to decide whether inter-class rates should be adjusted based on those studies.

C. How should any rate increase be collected from the several customer classes?

Findings of Fact:

1. All of the A&E and BIP class cost of service studies indicate the residential

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[175] Brubaker Rebuttal, Ex. 504, Page 6, Lines 1-21.

[176] Post-Hearing Brief of the Office of the Public Counsel, Page 39.

and large transmission service (Noranda) classes are currently providing below average returns. That means those classes should contribute a greater share of Ameren Missouri's revenues than they currently are if they are to match their class cost of service. All studies also show that the small general service, large general service and small primary service are providing above average returns. That means they are currently contributing a greater share of revenue than would be indicated by their class cost of service. The other rate classes contribute revenues close to their cost of service.[177]

2. Ameren Missouri, Public Counsel, MIEC, and all other signatories to the objected-to Noranda special rate stipulation and agreement suggest that no adjustments be made to the class contributions. Instead, they would apply any increases ordered in this case "across the board", in other words, equally to all the customer classes.

3. Staff, MECG, and Wal-Mart would make some adjustments to bring the classes closer to their cost of service. Staff proposes a six-step process to bring the rate classes closer to their cost of service: 1) the Residential and LTS classes would receive a positive .50% revenue neutral adjustment, meaning their rates would increase 0.50% even before any rate increase that would result from this case. The small general service, large general service and small primary service would receive a negative 0.63% revenue neutral adjustment. 2) The portion of the revenue increase or decrease that is attributable to the amortization of the energy efficiency programs from the pre-MEEIA program costs would be assigned directly to the applicable customer classes. 3) The amount of revenue increase awarded to Ameren Missouri that is not associated with step 2 would be determined. 4) Ameren Missouri's rate schedules would be made uniform for certain interrelationships

[177] For example, *see*, Warwick Direct, Ex. 49, Sch. WMW-1.

among the non-residential rate schedules that are integral to Ameren Missouri's rate design. 5) The residential customer charge would remain at $8.00. 6) After steps 1-5 are accomplished, any additional rate increase would apply across the board to all rate classes.[178]

4. MECG and Wal-Mart are particularly concerned about the large general service and small primary service classes. They presented evidence to show that the over-recovery from those classes has been long-standing, going back to the 2007 rate case.[179] To move toward actual cost of service, they ask the Commission to apply a 25% revenue neutral movement toward cost of service, while ensuring that no class receive a rate increase greater than 9.65%.[180]

5. Ameren Missouri has indicated that, aside from leaving the customer charge at $8.00, Staff's proposal is reasonable and would be acceptable. It also indicates that Wal-Mart's rate design proposal is reasonable.[181]

6. The small general service, large general service and small primary service rate classes have received negative rate adjustments in past Ameren Missouri rate cases, meaning the Commission has acted to move those classes closer to their cost of service. In ER-2010-0036, that negative adjustment was 0.61 percent, in ER-2011-0028 it was 1.78 percent, and in ER-2013-0166, it was 0.18 percent.[182]

7. The contribution collected from the various classes can change because of

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[178] Scheperle Direct, Ex. 232, Pages 3-4, Lines 17-21, 1-32.

[179] Chriss Cost of Service Direct, Ex. 751, Page 6, Tables 2 and 3.

[180] Chriss Cost of Service Direct, Ex. 751, Pages 9-10, Lines 18-22, 1-6.

[181] Transcript, Page 1494, Lines 2-11.

[182] Fortson Rebuttal, Ex. 215, Schedule BJF-R1.

factors other than Commission action to adjust rates.[183] For example, even though the residential rate class is currently above its cost of service, over time, because of energy savings and the way the allocations work, they will move closer to their cost of service without any rate adjustments by the Commission.[184]

Conclusions of Law:

A. Commission Rule 4 CSR 240-2.115(2)(D) states:

> A nonunanimous stipulation and agreement to which a timely objection has been filed shall be considered to be merely a position of the signatory parties to the stipulated position, except that no party shall be bound by it. All issues shall remain for determination after hearing.

Decision:

The Commission agrees with Staff, MECG, and Wal-Mart that the existing class contributions to rates are out of balance. The only question is how much of an adjustment should be made to move the rate classes toward their cost of service as shown in the class cost of service studies. The Wal-Mart proposal would move the large general service and small primary service classes to their cost of service more quickly than Staff's proposal, but it would also have a greater impact on the classes that would see larger than average increases, notably the residential class. To minimize rate shock for the classes that will see larger than system average increases, while still moving closer toward actual cost of service, the Commission will adopt Staff's six step proposal.

D. What should the Residential Class customer charge be?

Findings of Fact:

1. The customer charge is the set amount on every customer's bill that must be

[183] Transcript, Page 3022, Lines 2-25.

[184] Transcript, Page 1497, Lines 1-7.

paid even if the customer uses no electricity.

2. Customer-related costs are the minimum costs necessary to make electric service available to the customer, regardless of how much electricity the customer uses. Examples include meter reading, billing, postage, customer account service, and a portion of the costs associated with required investment in a meter, the service line drop, and other billing costs.[185] Customer-related costs are generally recovered through the customer charge while other costs are recovered through volumetric rates that vary with the amount of electricity used.

3. It is important to remember that determining an appropriate customer charge is a question of rate design, not a question of the company's revenue requirement. That means any increase in the company's customer charge would be accompanied by a decrease in volumetric rates so that, in theory, the company recovers the same amount of revenue.

4. In actual practice, because the amount collected from volumetric rates varies with the amount of electricity used, the company will collect less money from volumetric rates when customers use less electricity. Thus, for example, in a cool summer, when customers are using less air conditioning, the company runs the risk of collecting less revenue. For that reason, electric utilities prefer to lessen risk by collecting more of their charges through the fixed customer charge.

5. Ameren Missouri's current customer charge for residential customers is set at $8.00 per month. Staff's class cost of service study would support recovery of a customer

[185] Staff Report Rate Design, Ex. 201, Pages 43-44, Lines 29-31, 1-2.

charge of $8.11 but Staff recommends that the charge remain at $8.00.[186]

6. Ameren Missouri contends a customer charge of over $20 would be supported by the class cost of service studies,[187] but it only proposes to increase the residential customer charge by the same percentage as the overall rate increase that results from this case.[188] At Ameren Missouri's original rate increase that would have increased the customer charge to $8.77.[189] Since Ameren Missouri's requested increase is now lower, the customer charge increase request would be around $8.50. Since the Commission will not give Ameren Missouri the entire increase it has requested, the residential customer charge would be something less than $8.50 under Ameren Missouri's proposal.

7. Because no party is arguing that the customer charge should be based on the results of a particular class cost of service report, the Commission will not address the details of those reports. In any event, the Commission is not bound to set the customer charges based solely on the details of the cost of service studies. 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.

8. 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

[186] Staff Report Rate Design, Ex. 201, Page 43, Lines 26-28.

[187] Davis Rebuttal, Ex.9, Page 13, Line 1.

[188] Transcript, Page 1498, Lines 16-25.

[189] Davis Rebuttal, Ex. 9, Page 11, Lines 4-5.

monthly charge where it is gives the customer more control.

9. Since Ameren Missouri has not shown a strong reason to increase the customer charge and is seeking only a small, largely token increase, the Commission finds that the existing customer charges for the residential class should not be increased.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The Commission finds that Ameren Missouri's customer charges for residential customers shall remain at $8.00.

E. Should the Commission approve Wal-Mart's proposed shift to increase the demand component of the hours-use rate design for Large General Service and Small Primary Service?

Findings of Fact:

1. This sub-issue concerns rate design only within the large general service and small primary service class. Wal-Mart looked at Ameren Missouri's class cost of service study and noted that approximately 66.1% of non-energy efficiency base revenues for that class are demand-related, while 31.7% are energy related. However, under the "hours-use" intra-class rate design structure used by Ameren Missouri, a large portion of the class' demand-related costs are collected through energy charges.[190]

2. The large general service and small primary service class currently uses a declining three-block "hours-use" rate structure. As usage moves up to the next block, the rate declines. The "hours-use" rate structure has the effect of shifting demand cost

[190] Chriss Cost of Service Direct, Ex. 751, Page 11, Lines 15-22.

responsibility from lower load factor customers to those with higher load factors.[191] Wal-Mart is a higher load factor customer and does not want to subsidize other customers within its rate class.[192]

3. Ameren Missouri would spread the increase resulting from this rate case equally among the three blocks. Wal-Mart proposes that the second and third block energy rates remain at their current levels and that the customer charge for the class be increased by the percentage of overall revenue increase. Half of the remaining overall increase would be applied to the first block energy charge and the other half to the demand charge.[193]

4. Wal-Mart's proposal would have a large and unfavorable impact on lower load factor customers, possibly resulting in double digit percentage increases for those customers, in addition to whatever rate increase results from this case. Meanwhile, the proposal would reduce rates for higher load customers by only a few percentage points.[194]

5. The "hours-use" rate design has been in use in Missouri since 1990 when the Commission approved its use as part of a settlement of a revenue complaint case and a rate design case.[195]

6. All the other investor-owned electric utilities in Missouri use an "hours-use"

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[191] Chriss Cost of Service Direct, Ex. 751, Page 12, Lines 1-14.

[192] Chriss Cost of Service Direct, Ex. 751, Page 13, Lines 1-7.

[193] Chriss Cost of Service Direct, Ex. 751, Page 17, Lines 14-20.

[194] Davis Rebuttal, Ex. 9, Page 9. Lines 4-15. *In the Matter of the Investigation of Union Electric Company's Class Allocation and Rate Design,* Report and Order, Case No. EO-87-175, 30 Mo. P.S.C. (N.S.) 406 (1990).

[195] Davis Rebuttal, Ex. 9, Pages 7-8, Lines 21-22, 1-10.

rate design for the non-residential customers.[196]

7. Staff recommends against accepting Wal-Mart's proposal because it believes more study is needed to assess the rate impact of the proposed changes on the 11,000 other customers in those rate classes.[197]

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

Wal-Mart is proposing a change in a long-standing rate structure that could have significant rate impact on 11,000 customers. There is not enough evidence in the record for this case to justify making that change at this time. The Commission is willing to examine this question in more detail in Ameren Missouri's next rate case and expects the parties to more fully develop the evidence at that time. The Commission will not adopt Wal-Mart's proposal at this time.

F. Should the Commission approve Wal-Mart's recommendation to require the Company to present analyses of alternatives to the hours-use rate design in its next rate case?

Findings of Fact:

1. As discussed in the previous sub-issue, Wal-Mart is generally dissatisfied with the "hours-use" rate design used by Ameren Missouri and all other electric utilities in Missouri. It asks the Commission to order Ameren Missouri to develop alternative rate designs for the large general service and small primary class that more closely reflect the company's cost of service and do not use the hours-use rate design for the energy charge. It asks that Ameren Missouri be ordered to present those alternatives in

[196] Fortson Rebuttal, Ex. 215, Pages 7-8, Lines 16-17, 1-2.

[197] Fortson Rebuttal, Ex. 215, Page 7, Lines 12-15.

its next base rate case.[198]

2. Ameren Missouri indicates it is satisfied with the current "hours-use" rate design and asserts that if Wal-Mart wants to see a change it has the ability to perform and pay for its own cost study.[199]

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

While the Commission is willing to look at this issue in the next rate case, it agrees that Wal-Mart has the resources to perform its own study and will not order Ameren Missouri to undertake the study proposed by Wal-Mart. Each party may perform its own study if it wishes to do so.

11. Economic Development Rate Design Mechanisms

A. Should the Commission expand the application of Ameren Missouri's existing Economic Development Riders?

Findings of Fact:

1. On October 20, 2014, the Commission issued an order in this case that directed the parties to address questions about rate design mechanisms that could be used to promote stability or growth of customer levels in geographic locations where existing infrastructure is underutilized. That order directed Staff to file testimony on that question and invited other parties to also address the issue.[200]

2. The responses from the parties to that question raised questions about the

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[198] Chriss Cost of Service Direct, Ex. 751, Pages 17-18, Lines 20-21, 1-2.

[199] Initial Post-Hearing Brief of Ameren Missouri, Page 150.

[200] Order Directing Consideration of a Certain Rate Design Question, File No. ER-2014-0258, October 20, 2014

scope and effectiveness of Ameren Missouri's existing Economic Development Riders.

3. Staff's response to the Commission's questions described Ameren Missouri's existing economic development riders and provided additional ideas for new or expanded programs. Staff did not recommend the Commission take any action at this time but recommended the Commission form a collaborative to collect ideas for future action from all interested stakeholders.[201]

4. Public Counsel also filed testimony discussing Ameren Missouri's existing Economic Development Riders and suggesting ideas for new or expanded programs. In particular, Public Counsel compared Ameren Missouri's existing Riders to those currently offered by Kansas City Power & Light Company and The Empire District Electric Company.[202]

5. Ameren Missouri filed the supplemental direct testimony of William Davis in response to the Commission's order. Davis' testimony describes the company's existing Economic Re-Development Rider (ERR). That Rider has been in place since 2007 and is designed to encourage re-development of certain sites in the City of St. Louis. Eligibility for participation in the Rider is limited to industrial and large commercial rate classes.[203]

6. Staff and Public Counsel also describe a more general Ameren Missouri Rider known as the Economic Development and Retention Rider (EDRR).[204]

7. On March 9, several parties signed and filed a non-unanimous stipulation and agreement regarding class cost of service and rate design. The primary focus of the

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[201] Staff Report Rate Design, Ex. 201, Page 45, Lines 18-20.

[202] Marke Direct, Ex. 403, Pages 3-23.

[203] Davis Supplemental Direct, Ex. 8.

[204] Marke Direct, Ex. 403, Page 18, and Staff Report Rate Design, Ex. 201, Page 48.

stipulation and agreement was the provision of a reduced rate for Noranda. But it also included an exemplar economic development tariff for Ameren Missouri. That proposed tariff was never discussed when evidence was presented at the hearing, as it was filed five days after the issue was heard. As a result, there is no evidentiary support for it in the record.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The Commission does not believe any action regarding Ameren Missouri's economic development riders is appropriate at this time. As will be noted subsequently in this order, the Commission will establish a collaborative to look at this issue more closely.

B. Should the Commission modify Ameren Missouri's existing Economic Development Riders to require recipients to participate in the Company's energy efficiency programs?

Findings of Fact:

1. The Division of Energy proposed that Ameren Missouri be directed to modify its existing economic development riders to require active participation in Ameren Missouri's MEEIA programs as a condition for participation in the riders.[205]

2. Ameren Missouri currently has two economic development riders in its tariffs. The Economic Re-Development Rider (ERR), which is designed to encourage re-development of certain sites in the City of St. Louis, and a more general Ameren Missouri Rider known as the Economic Development and Retention Rider (EDRR). Thus far only one customer has taken advantage of the EDRR.[206] No customers currently take service

[205] Lohraff Direct, Ex. 702, Page 2, Lines 10-13.

[206] Staff Report Rate Design, Ex. 201, Page 53, Lines 22-26.

under the ERR.[207]

3. MIEC, the party that represents many of the industrial-type customers who would be eligible to participate in the economic development riders opposed the idea of requiring participation in MEEIA as unnecessary and illegal.[208]

4. The other parties that responded to the request that participation in MEEIA be made a requirement to take service under an economic development rider raised questions and concerns about that proposal that can best be addressed through a collaborative process.[209]

Conclusions of Law:

A. The MEEIA statute, specifically section 393.1075.7, RSMo (Cum. Supp. 2013), allows certain large users of electricity to opt out of participation in MEEIA programs.

Decision:

Participation in Ameren Missouri's economic development riders is not robust at this time and adding criteria for participation will not encourage greater participation. The Commission will not make participation in MEEIA a requirement for receiving service through Ameren Missouri's economic development riders. As will be noted subsequently in this order, the Commission will establish a collaborative to look at this issue more closely.

C. Should the Commission open a docket to explore the role economic development riders have across regulated industries (i.e. water, electric, natural gas) and/or to further explore issues raised by parties in this case and issues the Commission

[207] Staff Report Rate Design, Ex. 201, Page 54, Lines 11-12.

[208] Brubaker Rebuttal, Ex. 504, Pages 25-26.

[209] *See,* Davis Rebuttal, Ex. 9, Pages 35-37.

inquired about at the beginning of the case?

Findings of Fact:

1. Staff suggested the Commission open a collaborative to allow all interested stakeholders to discuss possible changes to Ameren Missouri's existing economic development riders.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The Commission will establish a collaborative process to more closely examine the use of economic development riders. The Commission will open a new working case for that purpose, and the parameters of that collaborative will be established in an order that will be issued in that new case.

12. Street Lighting

A. Can the Commission mandate or require that the Company sell its streetlights to the Cities?

Findings of Fact:

1. Ameren Missouri offers electricity to power municipal streetlights under two different provisions of its tariff. Under rate schedule 5(M), the municipal customer pays for the electricity needed to power the lights, but Ameren Missouri installs, owns and maintains the light fixtures, poles, wires, and other connections needed to provide street lighting. Ameren Missouri recovers those costs through the rate it charges the customer. Under the alternative 6(M) rate schedule, the municipal customer installs, owns, and maintains the light fixtures, poles, wires, and other connections, and pays a rate sufficient to recover the

cost of the electricity needed to power the lights.[210]

2. The Cities of O'Fallon and Ballwin note that the 6(M) rate for municipally-owned streetlight fixtures is lower than the corresponding 5(M) rate for streetlight fixtures owned by the company. They would like to explore the possibility of moving from the 5(M) rate to the lower 6(M) rate, believing that by doing so they could save a substantial amount of money.[211]

3. Steve Bender, Director of Public Works for the City of O'Fallon testified that his city pays over a million dollars per year under the 5(M) rate, but would pay only $180,000 per year under the 6(M) rate.[212] Robert Kuntz, City Administrator for the City of Ballwin, testified that his city would also pay less under the 6(M) rate.[213] Neither witness testified as to any additional costs the Cities would incur if they took responsibility for maintenance of the street lighting facilities under the 6(M) rate.

4. To qualify for service under the 6(M) tariff, the Cities must own their own streetlight fixtures. To that end, they have asked Ameren Missouri to negotiate to sell the fixtures at a fair market price.[214] Ameren Missouri has refused to enter into such negotiations.[215] The Cities ask the Commission to force Ameren Missouri to negotiate for the sale of the streetlights and have proposed a tariff modification to make that happen.[216]

5. Ameren Missouri explains that it is not interested in selling the streetlight

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[210] Davis Rebuttal, Ex. 9, Page 40, Lines 3-13.
[211] Bender Direct, Ex. 850, Page 3, Lines 6-12.
[212] Bender Direct, Ex. 850, Page 3, Lines 6-12.
[213] Kuntz Surrebuttal, Ex. 853, Page 4, Lines 8-12.
[214] Bender Direct, Ex. 850, Page 5, Lines 27-30.
[215] Wakeman Rebuttal, Ex. 46, Page 15, Lines 13-19.
[216] Bender Direct, Ex. 850, Attachment D.

fixtures to the Cities for two reasons. First, the company says it is in business to construct, own, and operate electrical distribution systems, including streetlights, not to build such systems for sale to other entities. Second, the company does not want to sell the streetlight fixtures because they are an integrated part of its electrical distribution system. [217]

6. David Wakeman, Ameren Missouri's Senior Vice President of Operations and Technical Services,[218] testified, and the Commission finds, that the component parts of the streetlight facilities are much more than just the light fixtures and poles visible from the street. As Wakeman explained, those components include: "streetlight fixtures, streetlight poles, cables supplying power to those streetlights and the supply to the cable, which can include transformers or secondary pedestals."[219]

7. The mere existence of these other components is not the only complicating factor. The real problem is that the other components are also used by Ameren Missouri to supply electric service to its other customers. The cables supplying power to the streetlights often share an underground trench with other distribution cables. The street light fixtures may be attached to poles that support other components of the overhead electric distribution system.[220]

8. For example, the electrical cable that feeds a streetlight might be fed out of a transformer that contains 12,000 volts of electricity and also serves the homes and businesses in the area.[221] Ameren Missouri's own technicians are trained to deal with that amount of electricity, but allowing other parties to have access to its electrical system would

[217] Wakeman Rebuttal, Ex. 46, Page 17, Lines 10-14.

[218] Wakeman Rebuttal, Ex. 46, Page 1, Lines 11-13.

[219] Wakeman Rebuttal, Ex. 46, Page 16, Lines 15-17.

[220] Wakeman Rebuttal, Ex. 46, Page 16, Lines 17-22.

[221] Transcript, Page 1809, Lines 18-25.

put them, as well as the system, at risk.[222]

9. To avoid that problem, if the Cities were to take ownership of the streetlights, Ameren Missouri would have to reconstruct the system to separate the streetlights from the electric system and install a disconnect switch so that the Cities could shut off power to the streetlights if they needed to perform maintenance work on them.[223]

10. Some cities do own street lights that are served under the 6(M) rates. Generally, such systems are installed by the developer of a new subdivision and are separated from the rest of the electric distribution system by a disconnecting device.[224] In fact, the City of O'Fallon has an ordinance that requires developers of new subdivisions to construct streetlights that would conform to Ameren Missouri's 6(M) lighting requirements.[225]

11. The Cities want to be able to move to the 6(M) rate because they contend the 5(M) rate for company owned facilities is clearly excessive. They believe the rate is excessive because the amount by which the 5(M) rate exceeds the 6(M) rate amounts to approximately $185.00 per fixture, per year. Over the 33-year life span for such fixtures established in the company's depreciation schedules, the Cities believe they would pay more than three times the value of each fixture.[226] The Cities imply that Ameren Missouri is refusing to sell the streetlights to them to keep them captive to what they believe to be an unreasonably high 5(M) rate.

12. The Cities misunderstand how the Commission sets rates for the street

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[222] Wakeman Rebuttal, Ex. 46, Page 17, Lines 18-23.

[223] Transcript Page 1811, Lines 8-13.

[224] Transcript, Page 1822, Lines 19-24.

[225] Transcript, Page 1860, Lines 12-22.

[226] Bender Direct, Ex. 850, Page 3, Lines 13-28.

lighting class of customers. As is explained in more detail later in this order, Ameren Missouri and other parties to this case perform class cost of service analysis to determine the cost to serve each of the various rate classes. For purposes of those studies, the company-owned 5(M) service classification is combined with the customer-owned 6(M) classification into a single lighting class.[227] The class cost of service studies prepared by Ameren Missouri, Staff and MIEC all show that the lighting class as a whole currently pays rates that are close to Ameren Missouri's cost to serve that class.[228] That means that, in the long term, Ameren Missouri's overall income from the lighting class will be the same whether the Cities take service under the 5(M) or the 6(M) classification. If the Cities switch from the 5(M) classification to the 6(M) classification, rates will be adjusted between those classifications in a future rate case to account for that change to allow Ameren Missouri to recover its costs to serve the lighting class. Thus, Ameren Missouri does not have a financial incentive to "trap" its customers in the 5(M) classification.

13. Ameren Missouri's 5(M) tariff contains a provision that allows a street lighting customer to give notice to the company of its desire to discontinue receiving 5(M) service. Neither City has thus far given such notice to Ameren Missouri.[229] Much of the Cities' concern about Ameren Missouri's action is based on a fear that if they gave such notice, Ameren Missouri would scrap the existing streetlight fixtures rather than sell them to the Cities in place. They contend that such action by the company would be economically

[227] Warwick Direct, Ex. 49, Page 5, Lines 7-10. Warwick's testimony indicates the company has three lighting classes, including "Municipal Lighting – Incandescent 7(M). The 7(M) classification has no customers and is to be eliminated in the revised tariffs that will result from this case. *See*. Davis Rebuttal, Ex. 9, Page 52, Lines 1-13.

[228] Davis Rebuttal, Ex. 9, Page 39, Lines 16-19.

[229] Transcript, Page 1864, Lines 3-6, as to the City of Ballwin. There is no indication in the record that the City of O'Fallon has issued such a notice.

wasteful and should be prevented by the Commission.

14. Because neither City has actually given notice of its intent to discontinue receiving 5(M) service, its concerns about economic waste from the scrapping of still useful streetlight fixtures is largely hypothetical. Ameren Missouri's witness, David Wakeman, testified several times that he did not know what the company would actually do with the existing street lighting fixtures if the Cities chose to discontinue 5(M) service.[230]

15. This is not the first time the Cities have brought this matter to the Commission's attention. In April 2014, the Cities filed a complaint before the Commission seeking to force Ameren Missouri to negotiate the sale of its street lighting facilities. The Commission handled that complaint in File No. EC-2014-0316. In August 2014, the Commission dismissed that complaint for failure to state a claim upon which relief can be granted, finding that it has no authority to order Ameren Missouri to sell property that it does not wish to sell. The Cities' appeal of the dismissal of their complaint is currently pending before Missouri's Western District Court of Appeals.[231]

Conclusions of Law:

A. The Cities claim that Section 393.140(5), RSMo 2000, gives the Commission authority to order Ameren Missouri to negotiate the sale of its street lighting fixtures to the Cities. The relevant portion of that statute says:

> Whenever the commission shall be of the opinion, after a hearing had upon its own motion or upon complaint, that … the acts or regulations of any such persons or corporations are unjust, unreasonable, unjustly discriminatory or unduly preferential or in any wise in violation of any provision of law, the commission shall determine and prescribe … the just and reasonable acts and regulations to be done and observed.

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[230] Transcript, Page 1797, Lines 13-24. *See also*, Page 1834, Lines 13-19.

[231] The pending appeal's file number at the Court of Appeals is WD78067.

On that basis, the Cities assert the Commission has authority to find that Ameren Missouri's refusal to negotiate the sale of the street lighting fixtures, and particularly its threat to scrap the fixtures rather than sell them to the Cities, is unjust and unreasonable and should be prohibited.

B. The specific statute that governs the transfer of utility property, Section 393.190.1, RSMo (Cum. Supp. 2013), in relevant part, says:

> No … electrical corporation … shall hereafter sell, assign, lease, transfer, mortgage or otherwise dispose of or encumber the whole or any part of its franchise, works or system, necessary or useful in the performance of its duties to the public, … without having first secured from the commission an order authorizing it so to do.

While that statute declares what the utility must do if it wants to sell used and useful property, it does not declare that the Commission can order a utility to sell such property. The Commission has only the authority given it explicitly by statute or reasonably incidental to such authority.[232] Thus, from negative implication, the Commission has no such authority.

C. Further, Section 71.525, RSMo 2000, restricts the ability of a municipality to condemn the used and useful property of a public utility if the municipality will use the property for the same or substantially similar purpose as the public utility. Subsection 71.525.3 goes on to make it clear that the limitations on condemnation apply "no matter whether any other … provision of law appears to convey the power of condemnation of such property by implication." Essentially, the Cities are asking the Commission to condemn Ameren Missouri's property to allow them to operate a street lighting system in

[232] *State ex rel. Praxair v. Pub. Serv. Com'n*, 344 S.W.3d 178, 192 (Mo 2011).

the company's place. Such action is forbidden by the statute.[233]

D. The Cities cite a 1987 telephone case as an example of a Commission finding that it does have authority to force a utility to sell its property.[234] In that case, the Commission found that it had sufficient authority to require independent telephone companies to essentially sell the company-owned telephone equipment inside customer homes to the customers. The companies had been paid for that equipment through accelerate depreciation. However, the basis for the Commission's finding of authority was a mandate from the Federal Communications Commission to take such action to enable the development of competition in the telephone industry. There is no such federal mandate in this case, and the *Detariffing* case does not justify a finding of Commission authority to order the sale of the street lighting fixtures.

E. The Commission will take administrative notice of its decision in in File No. EC-2014-0316.

Decision:

There has been a great deal of confusion, misunderstanding, and frustration surrounding this issue. But the actual issue before the Commission is quite narrow. The Cities ask the Commission to order Ameren Missouri to implement a tariff that would compel the Company to negotiate the sale of its street lighting fixtures when demanded by its customers. After considering the evidence and the arguments presented by the parties, the Commission decides that the tariff proposed by the Cities is not appropriate.

Previously, when the Cities filed a complaint to bring this question before the

[233] *See also*, *City of Kirkwood v. Union Electric. Co.*, 896 S.W.2d 946 (Mo. App. E.D. 1995).

[234] *Investigation of the Detariffing of Embedded Customer Premises Equipment (CPE) Owned by Independent Telephone Companies*, 29 Mo. P.S.C. (N.S.) 299 (1987).

Commission, the Commission concluded that the complaint should be dismissed without a hearing because the Commission does not have authority to force Ameren Missouri to sell its property. The Commission will not contradict that earlier conclusion.

Further, having now heard evidence about the factual basis for the Cities' claim to Ameren Missouri's property, the Commission also concludes that the Cities' claim must fail on its facts. Even if it is assumed that Section 393.140(5), RSMo 2000, gives the Commission authority to compel Ameren Missouri to negotiate to sell its street lighting fixtures to correct an unjust or unreasonable act or regulation of the company, the Cities have not shown that Ameren Missouri has done anything unjust or unreasonable.

The cornerstone of the Cities' argument is that Ameren Missouri would be acting unreasonably and would be wasting ratepayer money if it were to actually choose to scrap the street lighting fixtures rather than allow the Cities an opportunity to buy them. Certainly, the Commission would closely examine the prudence of that decision in any future rate case where the company sought to recover such costs in rates. But at this time that is purely a hypothetical concern rather than a basis for granting relief to the Cities. The Commission will not require Ameren Missouri to implement a tariff requiring it to negotiate to sell its property to the Cities.

B. Should the Commission approve a revenue-neutral adjustment between customer-owned and Company-owned lighting rates?

Findings of Fact:

1. As previously discussed, the class cost of service studies prepared by all the parties to this case showed that the revenue Ameren Missouri collects from the overall

lighting class closely matches the company's cost to serve that class of customers.[235] But in response to the Cities' claim that the 5(M) rate was unreasonable, Ameren Missouri's witness, William Davis, took a closer look at the intra-class balance of the 5(M) and 6(M) rates. In his rebuttal testimony, Davis reports that the 5(M) rates are currently above their costs of service, and the 6(M) rates are correspondingly below their cost of service.[236]

2. To adjust the 5(M) and 6(M) rate to make them match their actual cost of service would require a $3.9 million increase to the 6(M) rate schedule, with a corresponding $3.9 million decrease to the 5(M) rate. Because the 6(M) rate class is much smaller than the 5(M) rate class, the $3.9 million shift would roughly double the rates for the 6(M) rate class while reducing the rates for the 5(M) rate class by about 11 percent.[237] The shift would be revenue neutral for Ameren Missouri.

3. William Davis suggested the Commission might want to take steps in this rate case to move the 5(M) and 6(M) rate classifications closer to their actual costs of service. He proposes a gradual shifting of those costs to avoid a rate shock for the 6(M) customers, but did not actually propose such a shift in this case. Since he did not raise the possible rate shift until he filed his rebuttal testimony, the other parties did not have an opportunity to verify Davis' intra-class cost of service findings.

Conclusions of Law:

The Commission makes no additional conclusions of law for this sub-issue.

Decision:

The Commission is concerned that Ameren Missouri's cost recovery from the 5(M)

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[235] Davis Rebuttal, Ex. 9, Page 39, Lines 16-19.

[236] Davis Rebuttal, Ex. 9, Page 40, Lines 16-21.

[237] Davis Rebuttal, Ex. 9, Pages 40-41, Lines 21-23, 1-2.

and 6(M) classification within the overall lighting class be balanced to match the company's cost to serve those classifications. However, the Commission is not willing to make such rate shifts until all parties have an opportunity to review the basis for such a shift.

The Commission will not order a rate shift between the 5(M) and 6(M) rate classifications at this time, but will direct Ameren Missouri to further study the appropriateness of the 5(M) rate compared to the 6(M) and to present the results of that study in its direct case for its next rate case.

C. Should the Commission eliminate the termination fees from the Ameren Missouri-owned lighting rate?

Findings of Fact:

1. The Cities challenge a provision in Ameren Missouri's current lighting tariffs that creates a $100 per lamp early termination fee applicable if a street lighting customer in the 5(M) classification asks the company to remove the fixtures within either three or ten years of the installation of the fixture, depending upon the type of fixture to be removed. The Cities denounced that early termination fee as an unreasonable barrier to their goal of migrating from the 5(M) classification to the 6(M) classification.[238]

2. The early termination fees would apply to about ten percent of the total streetlights in the two cities.[239]

3. The fee is not designed to recover the full cost of the street lighting fixtures that would be removed. Rather, the early termination fee is intended to give a customer pause before requesting a change in a lighting service. For example, it is designed to discourage a customer from initially requesting a mercury vapor light and three months

[238] Bender Direct, Ex. 850, Page 4, Lines 16-27.

[239] Transcript, Page 1861, Lines 20-24, and Page 1864, lines 15-18.

later asking to change to a high pressure sodium light.[240]

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The early termination fee is a reasonable provision in Ameren Missouri's lighting tariff designed to ensure the costs incurred by the company are paid by the customers that cause that cost. The Commission will not order Ameren Missouri to remove that fee from its tariff.

13. Labadie ESPs

A. Should the Company's investment in electrostatic precipitators installed at the Labadie Energy Center be included in the Company's rate base?

Findings of Fact:

1. Ameren Missouri has installed electrostatic precipitators (ESPs)[241] at Units 1 and 2 of its coal-fired Labadie Energy Center to comply with the U.S. Environmental Protection Agency's (EPA's) Mercury and Air Toxics Standards (MATS) rule.[242] It now seeks to add the installation costs to its rate base.

2. Staff determined that the construction and testing requirements for the ESP's for Unit 2 were completed in August 2014 and for Unit 1 in December 2014. The ESPs for both units were fully operational and in-service before the December 31, 2014 end of the

[240] Davis Rebuttal, Ex. 9, Page 43, Lines 7-18.

[241] Staff describes the ESPs as "highly efficient filtration devices consisting of several chambers that contain numerous electro-statically charged steel plates that collect and remove fine particulate matter from flowing emission gases." Staff Revenue Requirement Report, Ex. 202, Page 49, Lines 14-16.

[242] Michels, Amended Rebuttal, Ex. 26, Page 2, Lines 13-16.

true-up period.[243]

3. Staff has reviewed the installation of the ESPs and has determined the trued-up costs pertaining to that project as of December 31, 2014.[244]

4. No party challenged the fact that the ESPs are used and useful or the amount of costs incurred to install the pollution control devices. However, Sierra Club challenged the prudence of Ameren Missouri's decision to install the ESPs. Sierra Club does not oppose pollution control devices in general but contends Ameren Missouri has not sufficiently studied the relative cost of immediately shutting down the Labadie coal-fired plant rather than incurring the cost to install the ESPs and additional pollution control devices that will need to be installed in the future, as well as the possibility that the plant will need to be shut down in the relatively near future to comply with the U.S. Environmental Protection Agency's proposed carbon limiting regulations.[245]

5. In response to Sierra Club's criticisms, Ameren Missouri offered the rebuttal testimony of Matt Michels, Ameren Missouri's Senior Manager of Corporate Analysis. Mr. Michels pointed to Ameren Missouri's recent Integrated Resource Plan (IRP) filing to demonstrate that installing the ESPs and keeping the plant in operation was cost effective.[246]

6. In response to Michels' rebuttal testimony, Sierra Club's witness, Dr. Hausman, narrowed his criticism of Ameren Missouri's Labadie analysis to two points.[247]

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[243] Staff Revenue Requirement Report, Ex. 202, Page 49, Lines 17-28.

[244] Carle Surrebuttal, Ex. 208, Page 5, Lines 12-14. The precise cost is highly confidential.

[245] Hausman Direct, Ex. 900, Pages 5-13.

[246] Michels Rebuttal, Ex. 26.

[247] Sierra Club's briefs also delve into broader criticisms of Ameren Missouri's IRP filing. The overall adequacy of the IRP filing is not being litigated in this proceeding. The only issue before the

First, he disagrees with Ameren Missouri's modeling in its IRP of the cost of compliance with greenhouse gas restrictions that might be imposed by the EPA's proposed Clean Power Plan.[248] Second, he contends Ameren Missouri should have modeled the option of retiring either Labadie Unit 1 or Unit 2 individually rather than as the whole plant because perhaps one unit could be retired without requiring any investment in replacement generation or transmission upgrades, even if the entire plant could not.[249]

7. Because of these deficiencies, Hausman recommends the Commission refuse to allow Ameren Missouri to include the ESP installation costs in rate base until the company "resolves these deficiencies and presents the Commission with an adequate justification for the prudence of these expenditures."[250]

8. The EPA's proposed Clean Power Plan was proposed in June 2014, but it is not yet in final form and no one knows how the final regulation regulate carbon emissions. Ameren Missouri's IRP analysis assumed that there was an 85 percent chance that any carbon restricting regulation would require indirect regulation of carbon emissions rather than placing a specific price on such emissions.[251] The currently proposed regulations do not include a carbon tax or a cap and trade regime that would impose such direct costs.[252]

9. The alternative to imposition of a direct cost on carbon emissions is indirect regulation where instead of making carbon emissions more expensive directly, the regulation would require utilities to replace polluting generating sources with less polluting

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Commission at this time is the prudence of Ameren Missouri's decision to install the ESPs at Labadie Units 1 and 2.

[248] Hausman Surrebuttal, Ex. 901, Pages 5-9.

[249] Hausman Surrebuttal, Ex. 901, Page 10, Lines 1-15.

[250] Hausman Surrebuttal, Ex. 901, Page 9, Lines 18-22.

[251] Transcript, Page 1937, Lines 12-25.

[252] Transcript, Pages 1942-1943, Lines 24-25, 1-3.

sources. So, for example, a coal-fired plant might be replaced by a natural gas-fired combined-cycle plant.[253] That also means that less efficient coal-fired plants, plants that produce more carbon dioxide because they are less efficient, would be retired before the Labadie plant, which is relatively efficient.[254] The retirement of less efficient coal fired plants would increase electricity prices, which would make the Labadie plant more profitable[255]

10. Based on that scenario, which Ameren Missouri reasonably found to be most likely, Ameren Missouri's IRP study concluded that investing in environmental controls, along with other investments and operating costs needed to keep Labadie operating until 2023 would save customers $3.6 billion.[256]

11. Ameren Missouri is required to comply with the MATS rule by April 16, 2016. Ameren Missouri needed to either install the ESPs by that time, or shut down the Labadie plant by that date to comply with the rule.[257] Shutting down the Labadie plant by April 2016 would require additional upgrades to the transmission grid to ensure reliability as well as the addition of new generating capacity.[258]

Conclusions of Law:

A. Sierra Club challenges the prudence of Ameren Missouri's decision to install ESP's at Units 1 and 2 of its Labadie Plant rather than shut down the plant by April 2016 in order to comply with the MATS standards. That challenge implicates what is described as

[253] Transcript, Page 1943, Lines 3-24.

[254] Transcript, Page 1949, Lines 10-25.

[255] Transcript, Page 1938, Lines 17-25.

[256] Michels Amended Rebuttal, Ex. 26, Page 12, Lines 6-10.

[257] Michels Amended Rebuttal, Ex. 26, Page 17, Lines 6-10. *See also*, Hausman Direct, Ex. 900, Page 9, Lines 1-13.

[258] Michels Amended Rebuttal, Ex. 26. Page 18, Lines 10-16.

the prudence standard. Missouri's courts have described that standard as follows:

> A utility's costs are presumed to be prudently incurred. The presumption does not, however, survive a showing of inefficiency or improvidence. If some other participant in the proceedings alleges that the utility has been imprudent in some manner, that participant has the burden of creating a serious doubt as to the prudence of the expenditure. If that is accomplished, the utility then has the burden of dispelling those doubts and proving the questioned expenditure was in fact prudent. The prudence test should not be based upon hindsight but upon reasonableness. The utility's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the utility had to solve its problem prospectively rather than in reliance on hindsight. In effect, the PSC's responsibility is to determine how reasonable people would have performed the tasks that confronted the utility.[259]

Thus, Sierra Club has the burden of demonstrating a serious doubt about the prudence of Ameren Missouri's decision before Ameren Missouri must defend its prudence

Decision:

Sierra Club has not carried its burden of demonstrating a serious doubt about the prudence of Ameren Missouri's decision to install ESPs at Unit 1 and Unit 2 of its Labadie plant. Indeed, Sierra Club does not actually allege that the installation of the ESPs at Labadie was imprudent. Rather, it contends Ameren Missouri did not perform a sufficient analysis of costs and benefits to properly determine whether customers would have been better off if the company had immediately shut down one or more of the Labadie units to comply with an April 2016 deadline to comply with the EPA's MATS regulation. Yet, Ameren Missouri's IRP analysis demonstrated that ratepayers would save approximately $3.6 billion if the Labadie plant remains on line until 2023.

Sierra Club also speculates that Ameren Missouri did not perform a sufficient analysis to assess the possibility that future greenhouse gas regulations might make

[259] *Atmos Energy Corp. v. Office of Public Counsel*, 389 S.W.3d 224, 228 (Mo. App. W.D. 2012).

continued operation of the Labadie plant financially unviable. Ameren Missouri's analysis took into account its reasonable evaluation of what such regulations would likely require, but no such greenhouse gas regulations are currently in effect, and no one can know with any certainty what form such regulations might take in the future.

Sierra Club's criticisms of Ameren Missouri's cost-benefit analysis may be an appropriate topic to be raised when Ameren Missouri's IRP filing is discussed, but Ameren Missouri's decision to install the now fully operational and in-service ESPs is presumed to be prudent. Those costs identified in Staff's testimony may be included in Ameren Missouri's rate base.

14. Fuel Adjustment Clause ("FAC")

The parties identified several sub-issues regarding Ameren Missouri's fuel adjustment clause (FAC). Many of those issues regarded disputes between Public Counsel and Ameren Missouri about the sufficiency and timeliness of the evidentiary support the company offered to justify continuation of the FAC. During the course of the hearing, Public Counsel and Ameren Missouri filed a non-unanimous stipulation and agreement that resolved all disagreements between those parties and allowed for the continuation of the FAC with a few changes that were incorporated into a proposed tariff attached to the stipulation and agreement.[260]

Consumers Council objected to the stipulation and agreement because it presupposes that the FAC will be continued, a result it opposes. Because of Consumers Council's objection, the Commission cannot approve the non-unanimous stipulation and

[260] Non-Unanimous Stipulation and Agreement Regarding Some Fuel Adjustment Clause Issues. Filed March 6, 2015.

agreement[261] and must resolve the issues based on competent and substantial evidence. The non-unanimous stipulation and agreement becomes merely a joint position statement of the signatory parties to which they are not bound. However, both Ameren Missouri and Public Counsel have indicated their intent to adhere to that joint position.

Should Ameren Missouri be allowed to continue to use a fuel adjustment clause?

Findings of Fact:

1. Before addressing other issues regarding the implementation of Ameren Missouri's fuel adjustment clause, the Commission must address the fundamental issue of whether Ameren Missouri should be allowed to continue to use a fuel adjustment clause.

2. The Commission first allowed Ameren Missouri to implement a fuel adjustment clause in a previous Ameren Missouri rate case, ER-2008-0318. .[262] The approved fuel adjustment clause includes an incentive mechanism that requires Ameren Missouri to pass through to its customers 95 percent of any deviation in fuel and purchased power costs from the base level. The other 5 percent of any deviation is retained or absorbed by Ameren Missouri.[263] The Commission has approved the continuation of that fuel adjustment clause in each subsequent Ameren Missouri rate case.

3. In this case, Ameren Missouri proposed that the Commission allow it to continue to use its existing fuel adjustment clause.[264] Consumers Council did not present

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[261] Commission Rule 4 CSR 240-2.115(D).

[262] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, 18 Mo. P.S.C. 3d 306, 361, January 27, 2009.

[263] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, 18 Mo. P.S.C. 3d 306, 366-367, January 27, 2009.

[264] Barnes Direct, Ex. 2, Pages 3-4, Lines 23,1-2.

any testimony on this issue, but it did cross examine witnesses presented by other parties and urged the Commission to discontinue Ameren Missouri's fuel adjustment clause. Consumers Council also asks the Commission to change the existing sharing mechanism to create a 50/50 split, with Ameren Missouri retaining or absorbing half of any deviation from the base level of fuel and purchased power costs. The Commission will address the proposed modification of the sharing mechanism in the next section of this report and order.

4. When it first allowed Ameren Missouri to implement a fuel adjustment clause in ER-2008-0318, the Commission found that Ameren Missouri should be allowed to establish a fuel adjustment clause because its fuel costs were substantial, beyond the control of the company's management, and volatile in amount. The Commission also found that Ameren Missouri needed a fuel adjustment clause to have a sufficient opportunity to earn a fair return on equity and to be able to compete for capital with other utilities that have a fuel adjustment clause.[265] In the same rate case, the Commission found that a 95/5 sharing mechanism would give Ameren Missouri a sufficient opportunity to earn a fair return on equity, while protecting customers by preserving the company's incentive to be prudent.[266]

5. Ameren Missouri's net energy costs have risen substantially since the last rate case to approximately $696 million, an increase of 23 percent.[267] Fuel and purchased

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[265] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, January 27, 2009, Pages 69-70.

[266] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, January 27, 2009, Page 76.

[267] Barnes Rebuttal, Ex. 3, Page 21, Lines 5-8.

power costs, including transportation, are still the company's largest operating and maintenance (O&M) expense, comprising approximately 51 percent of its total O&M costs.[268] Coal costs have increased, and off-system sales have declined. Further increases in coal costs are anticipated, and no one knows what will happen to off-system sales revenue.[269] Those fuel and purchased power costs continue to be dictated by national and international markets and thus are outside the control of Ameren Missouri's management. Finally, these costs and revenues continue to be volatile.[270]

6. Ameren Missouri still needs a fuel adjustment clause to help alleviate the effects of regulatory lag as net fuel costs continue to rise. In addition, Ameren Missouri still must compete in the capital markets with other utilities, and the vast majority of those utilities have fuel adjustment clauses. The continued existence of a fuel adjustment clause is important to maintaining Ameren Missouri's credit worthiness.[271]

7. Finally, Consumers Council expresses concern that the existence of the FAC has contributed to "excessive" earnings by Ameren Missouri. That claim of past "excessive" earnings is based on the per-book quarterly surveillance reports that Ameren Missouri has filed since it was first allowed to have an FAC in 2009. Such surveillance reports merely provide a snapshot of unadjusted book earnings[272] and are not suitable to establish just and reasonable rates. In any event, those surveillance reports show that Ameren Missouri was earning less than its authorized return on equity more often than it

[268] Barnes Rebuttal, Ex. 3, Page 21, Lines 1-5.

[269] Barnes Rebuttal, Ex. 3, Page 22, Lines 11-19.

[270] Barnes Rebuttal, Ex. 3, Page 25, Lines 1-9.

[271] Rygh Rebuttal, Ex. 42, Pages 6-16.

[272] Reed Surrebuttal, Ex. 41, Page 16, Lines 4-7.

was earning more than its authorized return during the five years since Ameren Missouri was first allowed to implement an FAC.[273]

Conclusions of Law:

A. Section 386.266.1, RSMo (Cum. Supp. 2013), allows the Commission to establish and continue a fuel adjustment clause for Ameren Missouri.

B. Commission Rule 4 CSR 240-2.115(2)(D) states:

> A nonunanimous stipulation and agreement to which a timely objection has been filed shall be considered to be merely a position of the signatory parties to the stipulated position, except that no party shall be bound by it. All issues shall remain for determination after hearing.

Decision:

Ameren Missouri still needs to have a fuel adjustment clause in place if it is to have a reasonable opportunity to earn a fair return on its investments. The Commission concludes Ameren Missouri should be allowed to continue to implement a fuel adjustment clause.

A. Did the Company fail to comply with the "complete explanation" provisions of 4 CSR 240-3.161(3)(H) and (I) and, if so, would this justify the elimination of the Company's fuel adjustment clause?

Findings of Fact:

1. As described in the conclusions of law for this issue, the Commission's rules regarding the FAC require that the electric utility seeking to continue an FAC file detailed information as part of its direct filing to institute the rate case. Public Counsel's witness, Lena Mantle, testified that Ameren Missouri failed to provide a complete explanation in its direct case of all the costs and revenues that it wanted to be included in its FAC.[274] On that basis, she urged the Commission to discontinue the FAC because the information Ameren

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[273] Reed Surrebuttal, Ex. 41, Pages 14-15, Figures 1 and 2.

[274] Mantle Direct, Ex. 400, Pages 9-10, Lines 16-22, 1-2.

Missouri filed did not provide the Commission with the information needed to make an informed decision.[275]

2. Ameren Missouri purported to offer the required minimum filings in an attachment to the direct testimony of Lynn Barnes.[276] When Public Counsel challenged the sufficiency of that filing, Barnes responded by testifying that the level of detail in Ameren Missouri's filing matches that offered in previous rate cases and that those previous filings have been found to be sufficient by Staff and the Commission.[277]

3. In the objected-to stipulation and agreement, now the joint position of Ameren Missouri and Public Counsel, those parties agreed to meet no later than May 30, 2015, to discuss additional information that Ameren Missouri should provide about costs and revenues when it files a request to continue its FAC in its next rate case. Ameren Missouri and Public Counsel agree to file their agreed-upon account, subaccount and activity code descriptions in this case by August 1, 2015. With that understanding, they agree the FAC should be continued in this case.

Conclusions of Law:

A. Commission rule 4 CSR 240-3.161 establishes certain filing requirements for electric utilities that are seeking to continue a previously established FAC. Subsection (3) of that rule says:

> When an electric utility files a general rate proceeding following the general rate proceeding that established its RAM [another word for FAC] as described by 4 CSR 240-20.090(2) in which it requests that its RAM be continued or modified, the electric utility shall file with the commission and serve parties … the following supporting information as part of, or in addition

[275] Mantle Direct, Ex. 400, Pages 17-18, Lines 20-23, 1.

[276] Ex. 3.

[277] Barnes Rebuttal, Ex. 3, Page 7, Lines 1-16. *See also, In the Matter of the Tariffs of Aquila, Inc.,* Report and Order, File No. ER-20107-0004, 15 Mo. P.S.C. 3d 416, May 17, 2007.

to, its direct testimony: …
(H) A complete explanation of all the costs that shall be considered for recovery under the proposed RAM and the specific account used for each cost item on the electric utility's books and records;
(I) A complete explanation of all the revenues that shall be considered in the determination of the amount eligible for recovery under the proposed RAM and the specific account where each such revenue item is recorded on the electric utility's books and records.

Decision:

The minimum filings Ameren Missouri made in this case are substantially similar to the filings it made in past rate cases and have never been challenged in the past. That does not mean those minimum filings cannot be improved in the future. Public Counsel and Ameren Missouri's agreement to meet to discuss those requirements is helpful, and the Commission anticipates the filing those parties intend to make by August 1. However, the dispute about the details of those filing is not a sufficient justification for the termination of the FAC. Ameren Missouri and Public Counsel have reached a reasonable settlement of their dispute, and the Commission will take no further action at this time.

B. Did the Company fail to provide information on the magnitude, volatility and the Company's ability to manage the costs and revenues that it proposes to include in its FAC and, if so, would this justify the elimination of the Company's fuel adjustment clause?

Findings of Fact:

1. In her direct testimony, Public Counsel's witness, Lena Mantle, testified that Ameren Missouri did not provide sufficiently detailed information about the magnitude, volatility and the company's ability to manage the costs and revenues that it proposes to include in its FAC.[278]

2. Ameren Missouri's witness, Lynn Barnes, offered limited, conclusory information about magnitude, volatility, and ability to manage costs and revenue within the

[278] Mantle Direct, Ex. 400, Pages 13-16.

FAC in her direct testimony.[279] In her rebuttal testimony, Barnes disagreed that detailed testimony was required when the utility is merely seeking to continue an existing FAC.[280] However, she then offered much more detailed testimony on that topic.[281]

3. Public Counsel and Ameren Missouri have entered into an objected-to stipulation and agreement which remains their joint position. In that joint position, Public Counsel drops its position that the FAC be eliminated.

Conclusions of Law:

A. In relevant part, Commission Rule 4 CSR 240-20.090(2)(C) says:

> In determining which cost components to include in a RAM, the commission will consider, but is not limited to considering, the magnitude of the costs, the ability of the utility to manage the costs, the volatility of the cost component and the incentive provided to the utility as a result of the inclusion or exclusion of a cost component. …

That regulation does not require the utility to file any specific information, nor does it require the utility to file such information in its direct case.

Decision:

The direct testimony offered by Ameren Missouri provided limited information about the continuing need for the FAC. However, when the sufficiency of that testimony was challenged by Public Counsel, Ameren Missouri responded with more extensive testimony in its rebuttal testimony. Ameren Missouri has provided sufficient information to allow the Commission to find that the FAC should be continued.

C. If the FAC continues should the sharing percentage be changed to 90%/10%?

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[279] Barnes Direct, Ex. 2, Page 5, Lines 6-22.

[280] Barnes Rebuttal, Ex. 3, Page 13, Lines 5-10.

[281] Barnes Rebuttal, Ex. 3, Pages 21-29.

Findings of Fact:

1. Under the current FAC, Ameren Missouri passes 95 percent of eligible costs and revenues through the FAC. The remaining 5 percent is not passed through the FAC so that Ameren Missouri will retain an incentive to minimize its costs and maximize its revenue. Public Counsel initially urged the Commission to modify the sharing percentages incorporated in the FAC from a 95/5 split to a 90/10 split.[282] Consumers Council did not present any additional testimony on this question, but if the Commission does not totally eliminate the FAC, it advocates for a 50-50 split between rate payers and shareholders.

2. Public Counsel and Ameren Missouri have entered into an objected-to stipulation and agreement which remains their joint position. In that joint position, Public Counsel drops its position that the sharing mechanism be changed.

3. Since Ameren Missouri has had an FAC with a 95/5 sharing split, that 5 percent share amounts to $38 million of prudently incurred net fuel costs that the company will never be able to recover.[283] Even to a company as large as Ameren Missouri, $38 million is a significant incentive.

4. Giving Ameren Missouri a greater incentive to minimize its costs and maximize its off-system sales would be meaningless if there is little the company can actually do to minimize costs or maximize off-system sales. In general, Ameren Missouri's fuel costs are dictated by national and international markets that are largely beyond the company's control.[284]

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[282] Mantle Direct, Ex. 400, Pages 23-25.

[283] Barnes Rebuttal, Ex. 3, Page 46, Lines 1-18.

[284] Barnes Rebuttal, Ex. 3, Page 53, Lines 18-22.

5. Most other utilities with FACs do not have a sharing mechanism at all.[285]

6. Ameren Missouri's existing FAC, with the 95/5, has allowed the company to borrow money at a lower cost. Ameren Missouri's witness, Gary Rygh, an investment banker with Barclays, PLC, explains:

> Since 2009 [when the FAC began] Ameren Missouri has raised approximately $1.2 billion of debt, and each time the cost of that debt came in below the prevailing index at the time instead of above the cost of the index which was the case in prior Ameren Missouri debt offerings. The savings total about $8.6 million in interest costs every year for the life of the bonds that Ameren Missouri issued.

Over the life of the bonds, the savings amount to approximately $210 million, which ends up reducing customer rates.[286]

7. Furthermore, changing the sharing percentage without a good reason to do so could erode investor confidence in the utility and in the state regulatory process.[287]

Conclusions of Law:

A. Section 386.266.1, RSMo (Cum. Supp. 2013), the statute that allows the Commission to establish a fuel adjustment clause provides as follows:

> Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge or periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation. The commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities.

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[285] Barnes Rebuttal, Ex. 3, Page 52, Lines 7-11.

[286] Rygh Rebuttal, Ex. 42, Page 20, Lines 14-21.

[287] Barnes Rebuttal, Ex. 3, Page 53, Lines 1-3. See also, Rygh Rebuttal, Ex. 42, Pages 14-19.

Subsection 4 of that statute sets out some of the provisions that must be included in a fuel adjustment clause as follows:

> The commission shall have the power to approve, modify, or reject adjustment mechanisms submitted under subsections 1 to 3 of this section only after providing the opportunity for a full hearing in a general rate proceeding, including a general rate proceeding initiated by complaint. The commission may approve such rate schedule after considering all relevant factors which may affect the cost or overall rates and charges of the corporation, provided that it finds that the adjustment mechanism set forth in the schedules:
>
> **(1) Is reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity;**
>
> (2) Includes provisions for an annual true-up which shall accurately and appropriately remedy any over- or under-collections, including interest at the utility's short-term borrowing rate, through subsequent rate adjustments or refunds;
>
> (3) In the case of an adjustment mechanism submitted under subsections 1 and 2 of this section, includes provisions requiring that the utility file a general rate case with the effective date of new rates to be no later than four years after the effective date of the commission order implementing the adjustment mechanism. …
>
> (4) In the case of an adjustment mechanism submitted under subsections 1 or 2 of this section, includes provisions for prudence reviews of the costs subject to the adjustment mechanism no less frequently than at eighteen-month intervals, and shall require refund of any imprudently incurred costs plus interest at the utility's short-term borrowing rate. (emphasis added)

Subsection 4(1) is emphasized because that is the key requirement of the statute. Any fuel adjustment clause the Commission allows Ameren Missouri to implement must be reasonably designed to allow the company a sufficient opportunity to earn a fair return on equity.

B. Subsection 7 of the fuel adjustment clause statute provides the Commission with further guidance, stating the Commission may:

> take into account any change in business risk to the corporation resulting from implementation of the adjustment mechanism in setting the corporation's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the corporation.

Finally, subsection 9 of that statute requires the Commission to promulgate rules to "govern the structure, content and operation of such rate adjustments, and the procedure for the submission, frequency, examination, hearing and approval of such rate adjustments." In compliance with the requirements of the statute, the Commission promulgated Commission Rule 4 CSR 240-3.161, which establishes in detail the procedures for submission, approval, and implementation of a fuel adjustment clause.

C. Specifically, Commission Rule 4 CSR 240-3.161(3) establishes minimum filing requirements for an electric utility that wishes to continue its fuel adjustment clause in a rate case subsequent to the rate case in which the fuel adjustment clause was established. Ameren Missouri has met those filing requirements.

Decision:

There is no sufficient reason to change the existing 95/5 sharing percentage under which Ameren Missouri has operated for the past several years. Imposing a significant financial burden on the company simply to experiment with an alternative sharing percentage would be unfair to the company. The Commission finds there is no reason to change the sharing percentages in the fuel adjustment clause The Commission will retain the current 95%-5% sharing mechanism included in Ameren Missouri's fuel adjustment clause.

D. What transmission charges should be included in the FAC?

Findings of Fact:

1. As will be discussed in more detail in the Conclusions of Law for this issue, the Missouri statute that allows the Commission to establish a fuel adjustment clause limits the application of the fuel adjustment clause to increases and decreases in fuel and

purchased-power costs, including transportation.[288]

2. Ameren Missouri currently includes all the MISO wholesale transmission expense it incurs in the fuel adjustment clause, as it was allowed to do by the Commission in the last Ameren Missouri rate case.[289]

3. The Commission's decision in the last rate case was challenged on appeal by several parties, including MIEC. The Commission's decision was upheld, but MIEC's argument that transmission costs for "purchased power" should not include transmission costs related to self-generated power was found by the court to have been raised for the first time at the appellate court. Thus it was not preserved for appeal and was not addressed by the court.[290] MIEC now raises that argument to the Commission for the first time.

4. By the terms of MISO's tariff, Ameren Missouri, as a result of its participation in the MISO market, sells all the power it generates into the MISO market and then purchases back all the power it needs to serve its native load from the MISO market.[291] That fact is not disputed by any party.

5. In other contexts, Ameren Missouri recognizes the distinction between serving its native load and making off-system sales. For example, when accounting for fuel costs, the company separates fuel expense to serve native load from fuel expense to make off-system sales.[292]

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[288] Section 386.266.1, RSMo (Cum. Supp. 2013).

[289] In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service, Report and Order, File No. ER-2012-0166, December 12, 2012.

[290] *In re Union Elec. Co.,* 422 S.W.3d 358 (Mo. App. W.D. 2013).

[291] Haro Rebuttal, Ex. 14, Page 18, Lines 1-17.

[292] Dauphinais Surrebuttal, Ex. 509, Page 9, Lines 1-13. *And see* Exhibits. 524-528

6. In addition to the distinction between serving native load and making off-system sales, Ameren Missouri can also purchase power from MISO or other third parties to supplement its self-generated power.[293] All three scenarios are reasons why Ameren Missouri could incur wholesale transmission costs under FERC Account 565, and these are the transmission costs Ameren Missouri seeks to pass through its FAC.[294]

7. Furthermore, under FERC Order 668, public utilities must net their MISO-cleared load and generation in each hour and report that net amount as either: (i) sale for resale (i.e. off-system sale under account 447 when the utility's cleared generation exceeds the cleared load, or (ii) a power purchase under Account 555 when the utility's cleared load exceeds its cleared generation. That order states "Netting accurately reflects what participants would be recording on their books and records in the absence of the use of an RTO market to serve their native load."[295] That means that for accounting purposes, Ameren Missouri is required to recognize the distinction between off-system sales, power purchased to supplement its generation and self-generated power .

8. The transmission charges that Ameren Missouri is incurring from MISO are rapidly rising. This is principally due to MISO Schedule 26-A charges, which recover the cost of regionally funded Multi-Value Transmission Projects (MVPs). The Schedule 26-A rate was zero four years ago, but is expected to be $0.58 per MWh in 2015 and is forecasted to rise to $1.65 per MWh by 2021. Such an increase could increase the charges to Ameren Missouri by $40 million or more.[296]

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[293] Dauphinais Direct, Ex. 508, Page 4, Lines 12-17.

[294] Dauphinais Direct, Ex. 508, Page 4, Lines 9-12, and Page 6, Lines 19-20.

[295] Dauphinais Surrebuttal, Ex. 509, Page 10, Lines 7-22, and Ex. 66.

[296] Dauphinais Direct, Ex. 508, Page 5, Lines 1-13.

9. Ameren Missouri will be allowed to recover those increased costs in its future rates, but unless those costs are flowed through the FAC it will not be able to recover the increases that occur between rate cases.[297]

10. Only 3.5 percent of the MISO transmission charges incurred by Ameren Missouri to serve its load are related to true purchased power. The other 96.5 percent are incurred to transport power from Ameren Missouri's own generation to serve its own native load.[298]

11. The Commission has approved a unanimous stipulation and agreement on Net Base Energy Costs, which establishes how those transmission costs and revenues will be treated as well as the amount of costs that will be added to base rates if MISO transmission charges are not flowed through the FAC.[299]

Conclusions of Law:

A. Section 386.266.1, RSMo (Cum. Supp. 2013), the statute that allows the Commission to establish a fuel adjustment clause provides as follows:

> Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge or periodic rate adjustments outside of general rate proceedings **to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation.** The commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities. (emphasis added)

The emphasized clause limits the costs that can be flowed through the FAC for recovery

[297] Dauphinais Direct, Ex. 508, Page 5, Lines 13-21.

[298] Dauphinais Direct, Ex. 508, Page 11, Lines 1-18.

[299] Non-Unanimous Stipulation and Agreement Regarding Class Kilowatt-Hours, Revenues and Billing Determinants, Net Base Energy Costs, and Fuel Adjustment Clause Tariff Sheets, Filed March 5, 2015. Approved by Order issued on March 19, 2015.

between rate cases. It allows for recovery of transportation costs, which has been determined to include transmission costs, but such transmission costs are limited to those connected to purchased power costs.

Decision:

The evidence demonstrated that for purposes of operation of the MISO tariff, Ameren Missouri sells all the power it generates into the MISO market and buys back whatever power its needs to serve its native load. From that fact, Ameren Missouri leaps to its conclusion that since it sells all its power to MISO and buys all that power back, all such transactions are off-system sales and purchased power within the meaning of the FAC statute. The Commission does not accept this point of view.

The drafters of the FAC statute likely did not envision a situation where a utility would consider all its generation purchased power or off-system sales. In fact, the policy underlying the FAC statute is clear on its face. The statute is meant to insulate the utility from unexpected and uncontrollable fluctuations in transportation costs of purchased power. At the time the statute was drafted, and even in our more complex present-day system, the costs of transporting energy in addition to the energy generated by the utility or energy in excess of what the utility needs to serve it load are the costs that are unexpected and out of the utility's control to such an extent that a deviation from traditional rate making is justified.

Therefore, of the three reasons Ameren Missouri incurs transmission costs cited earlier, the costs that should be included in the FAC are 1) costs to transmit electric power it did not generate to its own load (true purchased power) and 2) costs to transmit excess electric power it is selling to third parties to locations outside of MISO (off-system sales).

Any other interpretation would expand the reach of the FAC beyond its intent.

E. If the FAC continues, what costs and revenues should be included in the Company's FAC?

1. Should only fuel and purchased power costs, transportation of the fuel commodity, transmission associated with purchased power costs and off-system sales revenues be included?
2. If costs and revenues other than those listed in item 1 above are included in the FAC, should cost or revenue types in which the Company has incurred less than $360,000 in the test year be included, and what charges and revenues from MISO should be included?

Findings of Fact:

1. In her rebuttal testimony,[300] Public Counsel's witness, Lena Mantle, described in detail what costs and revenues she believed should be flowed through the FAC. The objected-to stipulation and agreement, which is now the joint position of Public Counsel and Ameren Missouri, contains a sample tariff that incorporates the agreement between Public Counsel and the company regarding the costs and revenues to be flowed through the FAC.[301]

2. Consumers Council objected to the continuation of the FAC at a higher level, but did not file any testimony or make any argument at this level of granularity.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The sample tariff that was included as part of the joint position of Ameren Missouri and Public Counsel is a reasonable resolution of the question and may be used in so far as it is consistent with the other stipulations and agreements approved by the Commission.

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[300] Ex. 401.

[301] Non-Unanimous Stipulation and Agreement Regarding Some Fuel Adjustment Clause Issues, filed March 6, 2015.

3. Should transmission revenues continue to be included in the FAC?

This sub-issue was resolved by stipulation and agreement.[302]

15. Noranda Rate Proposal

A. Is Noranda experiencing a liquidity crisis such that it is likely to cease operations at its New Madrid smelter if it cannot obtain relief of the sort sought here?

1. If so, would the closure of the New Madrid smelter represent a significant detriment to the economy of Southeast Missouri, to local tax revenues, and to state tax revenues?

2. If so, can the Commission lawfully grant the requested relief?

3. If so, should the Commission grant the requested relief?

B. Would rates for Ameren Missouri's ratepayers other than Noranda be lower if Noranda remains on Ameren Missouri's system at the reduced rate?

C. Would it be more beneficial to Ameren Missouri's ratepayers other than Noranda for Noranda to remain on Ameren Missouri's system at the requested reduced rate than for Noranda to leave Ameren Missouri's system entirely?

D. Is it appropriate to redesign Ameren Missouri's tariffs and rates on the basis of Noranda's proposal, as described in its Direct Testimony and updated in its Surrebuttal Testimony?

1. If so, should Noranda be exempted from the FAC?

2. If so, should Noranda's rate increases be capped in any manner?

3. If so, can the Commission change the terms of Noranda's service obligation to Ameren Missouri and of Ameren Missouri's service obligation to Noranda?

4. If so, should the resulting revenue deficiency be made up by other rate payers in whole or in part?

5. If so, how should the amount of the resulting revenue deficiency be calculated?

6. If so, can the resulting revenue deficiency lawfully be allocated between ratepayers and Ameren Missouri's shareholders?

i. How should the revenue deficiency allocated to other ratepayers be allocated on an interclass basis?

ii. How should the revenue deficiency allocated to other ratepayers be allocated on an intra-class basis?

7. If so, what, if any conditions or commitments should the Commission require of Noranda?

[302] Non-Unanimous Stipulation and Agreement Regarding Class Kilowatt-Hours, Revenues and Billing Determinants, Net Base Energy Costs, and Fuel Adjustment Clause Tariff Sheets, filed on March 5, 2015, Paragraph 7.

E. What is Ameren Missouri's variable cost of service to Noranda?

1. Should this quantification of variable cost be offset by an allowance for Off-System Sales Margin Revenue?

2. What revenue benefit or detriment does the Ameren Missouri system receive from provision of service to Noranda at a rate of $32.50/MWh?

F. Should Noranda be served at a rate materially different than Ameren Missouri's fully distributed cost to serve them? If so, at what rate?

G. Is it appropriate to remove Noranda as a retail customer as proposed by Ameren Missouri in its Rebuttal Testimony?

1. Can the Commission cancel the Certificate of Convenience and Necessity that was granted for Ameren Missouri to provide service to Noranda and, if so, would the cancellation of the CCN be in the public interests?

2. Can the Commission grant Ameren Missouri's proposal since notification regarding the impact of this proposal on its other customers' bills was not provided to Ameren Missouri's customers?

3. If the Commission grants Ameren Missouri's proposal, should the costs and revenues flow through the FAC?

4. Can Ameren Missouri and Noranda end their current contract without approval of all of the parties to the Unanimous Stipulation and Agreement in the case in which Ameren Missouri was granted the CCN to serve Noranda?

The parties identified many decision points related to Noranda Aluminum's request to receive a rate less than Ameren Missouri's fully distributed cost to serve it. While most of those decision points will need to be addressed, the Commission finds that the entire issue should be addressed as a single issue rather than as several sub-issues.

Findings of Fact:

1. Noranda Aluminum, Inc. operates an aluminum smelter in New Madrid, Missouri, that takes electric service from Ameren Missouri. The smelter has been in operation since 1971 and annually produces approximately 260,000 metric tonnes of aluminum. That amounts to approximately 0.5 percent of the world's aluminum production and about 5 percent of the United States' aluminum production.[303] It employs approximately 900 workers.

[303] Boyles Direct, Ex. 600, Page 4, Lines 1-14.

2. Noranda uses approximately 4.2 million MegaWatt Hours (MWh) of electricity from Ameren Missouri in a year to make aluminum. Noranda uses 480 MWs of power, 24 hours per day, 7 days per week, 52 weeks per year. Every dollar per MWh change in Ameren Missouri's electricity rate represents a $4.2 million change in the pre-tax cash flow of Noranda.[304]

3. If Noranda were to close, the Missouri economy would forego approximately $9 billion in economic activity over the next twenty-five years. State and local tax revenue would be reduced by approximately $350 million over those same twenty-five years. Additional unemployment benefits resulting from the closure could be as high as $9.4 million.[305]

4. Noranda also has a tremendous positive impact on the Southeast region of Missouri, one of the poorest regions in the country, providing the few high paying jobs in the area.

5. Noranda is by far Ameren Missouri's largest customer, representing over ten percent of the total retail sales made by the utility.[306]

6. Noranda's current average base rate is $37.95 per MWh. It is also subject to operation of the FAC. Adding the current FAC of $4.40 brings the total rate to $42.35 per MWh.[307] Noranda's current rate is based on Ameren Missouri's fully allocated cost of service.

7. At the start of this case, Noranda proposed that it be given an initial total rate

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[304] Boyles Direct, Ex. 600, Page 8, Lines 16-20.

[305] Haslag Direct, Ex. 606, Pages 4-5, Lines 11-24, 1-16.

[306] Wills Amended Rebuttal, Ex. 53, Page 17, Lines 22-23.

[307] Brubaker Direct, Ex. 503, Page 40, Lines 1-9.

of $32.50 per MWh, to be increased by one percent annually, with that rate structure to remain in place for seven years.[308]

8. On March 9, 2015, just before this issue was heard, several consumer parties joined with Noranda in a non-unanimous stipulation and agreement.[309] Among other things, that stipulation and agreement would set the base rate for Noranda at $34.00 per MWh, would exempt Noranda from operation of the FAC, and would increase Noranda's future rates by half of the percentage increase that Ameren Missouri might obtain in any future rate case. Under the stipulation and agreement, that rate structure would remain in place for ten years.

9. Several parties objected to the stipulation and agreement, and according to the Commission's rule, the stipulation and agreement cannot be approved if any party objects to it. However, the stipulated position may remain the joint position of the parties that signed the stipulation and agreement. The Commission can approve that position if it finds that it is supported by competent and substantial evidence.[310]

10. The first step to determining whether either of the reduced rates proposed by Noranda is reasonable is to determine Ameren Missouri's incremental cost to serve Noranda. The experts also refer to incremental cost as Ameren Missouri's avoided cost, meaning the cost that Ameren Missouri would avoid if the Noranda smelter shuts down.[311] Either term means the point at which other ratepayers would benefit from Noranda's presence on the system. At any price above that point, Noranda is making a contribution

[308] Boyles Direct, Ex. 600, Page 3, Lines 9-13.

[309] The parties that signed the stipulation and agreement were Public Counsel, Noranda, Consumers Council, the Missouri Retailers Association, and MIEC.

[310] 4 CSR 240-2.115(2)(D).

[311] Transcript, Page 2792, Lines 23-25.

to Ameren Missouri's fixed costs.[312] At a price below that point, Noranda would not be making a contribution to Ameren Missouri's fixed costs and Ameren Missouri's other ratepayers would be better off without Noranda on the system.[313]

11. Incremental cost is largely influenced by the amount at which Ameren Missouri could sell power on the open market if it could no longer sell that power to Noranda.[314] MIEC's witness, James Dauphinais, testified that the incremental cost would be between \$28.03 and \$29.39 per MWh.[315] Staff's witness, Sarah Kliethermes, calculated incremental cost at \$31.50 per MWh.[316] In his rebuttal testimony, Ameren Missouri's witness, Matt Michels, calculated that point at either \$32.77 per MWh or \$34.13 per MWh.[317] At the hearing, he testified that for the period through May of 2017, the incremental cost would likely remain below \$32.50 per MWh.[318]

11. The actual future incremental cost is uncertain because it depends on the spot energy market prices and annual capacity market prices that will occur in the future.[319] 12. In setting a rate for Noranda, it is important that the rate be set, and remain, above the incremental cost. Below that cost, Noranda would not be covering any part of Ameren Missouri's fixed costs. If Noranda is not making any contribution to fixed

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[312] Transcript, Page 2793, Lines 11-19.

[313] Transcript, Page 2793, Lines 7-10.

[314] Dauphinais Direct, Ex. 508, Page 16, Lines 13-23.

[315] Dauphinais Direct, Ex. 508, Page 17, Lines 20-23.

[316] Transcript, Page 3003, Lines 14-22.

[317] Michels Amended Rebuttal, Ex. 26, Page 26, Lines 3-12. In his testimony, Michels describes those numbers as the Actual Net Energy Cost, or ANEC. At the hearing explained that ANEC is another name for incremental cost or avoided cost. See Transcript, Pages 2956-2957, Lines 22-25, 1-6.

[318] Transcript, Page 2946, Lines 10-18.

[319] Dauphinais Surrebuttal, Ex. 509, Page 25, Lines 14-18.

costs, there is no justification for allowing it to pay a reduced rate and other ratepayers would be better off if the smelter closed. But, so long as Noranda's rate remains above the incremental cost, Noranda will make a contribution to Ameren Missouri's fixed costs and other customers will pay a lower rate than they would if the smelter closed and went off Ameren Missouri's system.[320]

13. A rate below fully allocated cost of service and above incremental cost of service is only appropriate if the smelter will likely leave Ameren Missouri's system if not allowed a lower electric rate. The future viability of the smelter, and thus the likelihood Ameren Missouri would retain Noranda's load, is largely dependent on the price of aluminum metal on the world market.[321]

14. The world's aluminum price is established by trading on the London Metal Exchange (LME), which includes a U.S. Midwest premium applicable to the aluminum produced at the Noranda smelter.[322]

15. The price of aluminum is highly volatile. Over the last 30 years, the annual percentage changes in price vary from plus 44 percent to minus 33 percent. Large positive changes can be quickly followed by large negative changes. On the whole, the average annual percentage of change in price per year is 15.9 percent.[323] Removing the effect of general inflation, aluminum prices have trended downward since 1982 by an average of 0.3 percent per year.[324]

16. Demand for aluminum tends to be cyclical following the general business

[320] Transcript, Page 3003, Lines 4-13.

[321] Fayne Surrebuttal, Ex. 603, Pages 4-5, Lines 9-22, 1-12.

[322] Pratt Direct, Ex. 608, Page 3, Lines 5-12.

[323] Pratt Direct, Ex. 608, Page 3, Lines 18-24.

[324] Pratt Direct, Ex. 608, Page 5, Lines 5-7.

cycle and is concentrated in industrial sectors that experience large swings in demand. Swings in demand are amplified by an inventory cycle.[325]

17. The other side of the pricing equation, supply, tends to be inelastic because production capacity cannot be increased in the short term. Occasionally that results in large upward spikes in price. But more commonly supply is unresponsive on the downside. Aluminum smelters need to work at full capacity to minimize costs so small adjustments in production are not practical. So producers tend to keep producing even when demand falls, causing inventories to grow and prices to fall.[326]

18. The demand for aluminum is also affected by major price shocks caused by the effects of financial crises, wars, or other major world events. Such crises are certain to occur, but their timing is unpredictable.[327] As a result, forecasts of future aluminum prices can be unreliable.[328] There is little ability to predict the timing of an aluminum cycle beyond a year or two, and even a short-term prediction can be significantly wrong.[329]

19. To test its ability to survive the volatility of the aluminum market, Noranda ran several scenarios to “stress test” the smelter’s ability to survive. Based on those scenarios, Noranda believes that at some point, unless it receives a lower electric rate, it will exhaust its available credit and cash and will not be able to attract new investment. At that time, it will face a “substantial likelihood of imminent closure.”[330]

20. Ameren Missouri criticized the scenarios chosen by Noranda as

[325] Pratt Direct, Ex. 608, Pages 6-7, Lines 15-16, 1-13.

[326] Pratt Direct, Ex. 608, Page 7-8, Lines 15-26, 1-10.

[327] Pratt Direct, Ex. 608, Pages 9-10, Lines 1-14, 1-2.

[328] Pratt Direct, Ex. 608, Pages 16-20.

[329] Pratt Surrebuttal, Ex. 609, Page 6, Lines 1-4.

[330] Boyles Direct, Ex. 600, Page 20, Lines 4-11. See also, Boyles Surrebuttal, Ex. 601, Page 9, Lines 5-23.

unrepresentative of the most likely aluminum price forecasts. For example, if Noranda had used the future aluminum prices forecasted by CRU, a commodity sector consultancy, based in London[331] in its scenarios, it would not face a liquidity shortage.[332]

21. However, the scenarios are not intended to be forecasts of likely aluminum prices. Rather they are scenarios of what could happen to the smelter if certain aluminum prices develop.[333] And there is a substantial possibility of encountering a significant price downturn in at least one of the next six years. Such a downturn of at least 14.7 percent has occurred in every six-year period since 1982.[334]

22. Experts do rely on scenarios such as these to stress test business plans, assess ability to service loans, and assess ability to pay for power.[335] More importantly, lenders also use such stress testing to determine whether to loan money to a company. Banks and institutional lenders look at scenarios that use conservative forecasts when determining whether it is safe to loan money to a borrower.[336]

23. And the need to consider the views of lenders is important because Noranda will need to refinance substantial amounts of debt in the near future. Noranda's revolving asset based loan facility allows the company to obtain cash to run its day to day business operations. It will need to be refinanced in February 2017.[337] In addition, Noranda has a large amount of existing debt that comes due in 2019, which it will need to start refinancing

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[331] Humphreys Rebuttal, Ex. 19, Page 3, Lines 8-9.

[332] Mudge Rebuttal, Ex. 33, Page 17, Lines 1-7.

[333] Pratt Surrebuttal, Ex. 609, Page 6, Lines 14-22.

[334] Pratt Surrebuttal, Ex. 609, Page 7, Lines 14-21.

[335] Pratt Surrebuttal, Ex. 609, Page 8, Lines 1-11.

[336] Harris Surrebuttal, Ex. 605, Page 2, Lines 4-23.

[337] Boyles Direct, Ex. 600, Page 21, Lines 17-22.

in 2018.[338]

24. Steven Schwartz, an economist who testified for Noranda, explained that Noranda's operating performance in 2015 and expectations about 2016 will "color the way that potential lenders evaluate Noranda."[339] Schwartz further explained: "Creditors will lend Noranda money if its prospects seem likely to improve. Absent prospects for improvement, however, Noranda is an unattractive borrower."[340] If it is to improve its prospects, Noranda immediately needs a lower electric rate to improve its cash flow.

25. Noranda's refinancing difficulties are not just theoretical. Noranda has already been unable to obtain financing for construction of a new rod mill at the New Madrid smelter, causing a further drain on its cash resources.[341]

26. Tom Harris, a banker specializing in leverage finance for corporations, testified for Noranda that based upon his experience as a banker and leveraged financier, "Noranda will be unable to raise capital without first fundamentally improving its cash flow and thereby demonstrating its long-term viability".[342]

27. Noranda is heavily in debt. Its current leverage ratio is nearly seven times its last twelve-months' earnings.[343] Its debt to equity ratio was at 87 percent at the end of 2013.[344] Moody's and Standard & Poors have recently downgraded Noranda's credit

[338] Boyles Direct, Ex. 600, Page 22, Lines 20-23.
[339] Schwartz Direct, Ex. 610, Page 17, Lines 19-23.
[340] Schwartz, Direct, Ex. 610, Page 17, Lines 13-15.
[341] Harris Direct, Ex. 604, Page 3, Lines 13-22.
[342] Harris Direct, Ex. 604, Page 5, Lines 4-14.
[343] Harris Direct, Ex. 604, Page 5, lines 16-21.
[344] Mudge Rebuttal, Ex. 33, Page 37, Lines 8-9.

rating to a "highly speculative" grade of risk.[345]

28. In large part, Noranda's current financial plight is due to its heavy debt load, much of which was imposed upon it when it was acquired by Apollo, a private equity firm, in a leveraged buyout transaction in 2007. Apollo borrowed funds to buy Noranda, using the company's assets as collateral. It then used Noranda's assets to borrow more money to recoup its equity investment in the company and to pay itself additional dividends.[346]

29. Apollo no longer is the sole owner of Noranda. It is now a publicly traded company, although Apollo continues to own a third of its outstanding shares.[347]

30. Electricity is Noranda's largest single cost to make aluminum, comprising 31.8 percent of the total cost.[348] However, electricity is not the only cost to produce electricity, and Noranda has advantages over some other smelters for those costs.[349] If Noranda was granted the $32.50 rate it originally requested, it would have the lowest total production cost of any aluminum producer in the country.[350]

31. A chart prepared by Noranda witness, Henry Fayne, from data provided by CRU, shows that Noranda's current cost of electricity, at $42.50 per MWh, is the second highest among the nine remaining smelters in the United States. At a rate of $34 per MWh as proposed in the joint position, its rate would drop to the second lowest in the country.

Conclusions of Law:

A. Commission Rule 4 CSR 240-2.115(2)(D) states:

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[345] Boyles Direct, Ex. 600, Page 23, Lines 10-13.

[346] Mudge Rebuttal, Ex. 33, Pages 36-37, Lines 7-18, 1-9.

[347] Transcript, Page 2436, Lines 15-25.

[348] Schwartz Direct, Ex. 610, Page 8, lines 7-17.

[349] Mudge Rebuttal, Ex. 33, Page 49, Lines 8-19.

[350] Mudge Rebuttal, Ex. 33, Page 54, Lines 1-3.

> A nonunanimous stipulation and agreement to which a timely objection has been filed shall be considered to be merely a position of the signatory parties to the stipulated position, except that no party shall be bound by it. All issues shall remain for determination after hearing.

B. Section 393.130, RSMo (Cum. Supp. 2013), establishes the requirements for the provision of service by regulated utilities. In general, it requires that all charges for utility service must be "just and reasonable" and not more than allowed by law or order of this Commission. Subsection 2 of that statute further states:

> No … electrical corporation … shall directly or indirectly by any special rate, rebate, drawback or other device or method, charge, demand collect or receive from any person or corporation a greater or less compensation for … electricity …, except as authorized in this chapter, than it charges, demands, collects or receives from any other person or corporation for doing a like and contemporaneous service with respect thereto under the same or substantially similar circumstances or conditions.

Subsection 3 adds:

> No … electrical corporation … shall make or grant any undue or unreasonable preference or advantage to any person, corporation or locality, or to any particular description of service in any respect whatsoever, or subject any particular person, corporation or locality or any particular description of service to any undue or unreasonable prejudice or disadvantage in any respect whatsoever.

C. In sum, the statute says that utilities cannot give any "undue or unreasonable" preference to any particular customer, or class of customers. The most cited case interpreting the meaning of "undue or unreasonable" preference is *State ex rel. Laundry v. Public Service Commission*,[351] a 1931 decision by the Missouri Supreme Court. The *Laundry* decision arose from a complaint brought before the Commission by two laundry companies contending that they should be allowed to receive water service at the same reduced rate made available to ten manufacturing customers. The court found that the

[351] 34 S.W.2d 37 (Mo 1931)

special manufacturing rate had been put in place by the utility to try to draw more business into its service area. In its decision, the Supreme Court found that the laundries were similarly situated to the manufacturing customers and should have been allowed to take water at the reduced manufacturer's rate.

D. The *Laundry* decision merely decides that in the facts described in that case, the laundries should have qualified for the industrial rate. As a result, the Laundry court's views of economic development rates are largely dicta. However, Ameren Missouri cites to an even earlier Commission decision that the *Laundry* court quoted extensively for the proposition that all economic development rates are forbidden by the controlling statute. That Commission decision, *Civic League of St. Louis v. City of St. Louis*,[352] does indeed sharply criticize a water rate imposed by the City of St. Louis for the purpose of encouraging manufacturing enterprises to locate within the city and orders the city to revise those rates to avoid discrimination. However, the criticism was that the rates imposed by the City of St. Louis were set below the cost of service and that they were unreasonably low. In the words of that Commission:

> The establishment of the truth of such averment (that rates to manufacturers were below the cost of service) would reveal not only unquestionably unjust discrimination, but also an unreasonable low rate to this class (the manufacturers), and intolerable oppression upon the general metered water users in that they would be compelled to pay in part for water and service furnished to the favored class. The exercise of power crystallized into legislation that unjustly discriminates between users of water in this manner, in effect deprives those discriminated against of the use of their property without adequate compensation or due process of law, and turns it over to the favored class. It is in essence a species of taxation which takes the private property of the general or public metered water users for the private use of metered water users engaged in manufacturing. This is an abuse of power.[353]

[352] 4 Mo. P.S.C. 412 (1916).

[353] *Civic League* at 455-456.

While this decision speaks more directly to the propriety of below-cost rates, it does not necessarily contradict the principle set forth in *Laundry* that the Commission may set preferential rates as long as the preference is reasonably related to the cost of service and is not unduly or unreasonably preferential.[354] No party has identified any subsequent court decision that would go as far as proscribing all economic development or load retention type rates.

E. Instead, the courts that have examined this issue have made fact-based inquiries about the statutory proscription against unjust and unreasonable rates and undue or unreasonable preference or disadvantage and this is what the Commission must do here.[355]

F. The evidence in this case shows that Noranda is a unique customer because it uses much more electricity than any other Ameren Missouri customer. It uses that electricity at a very high load factor. It is so unique that it has had its own rate classification for many years. G. Under these circumstances, a rate for Noranda that is less than its fully allocated cost[356], but more than its incremental cost is just and reasonable within the meaning of Section 393.130, RSMo (Cum. Supp. 2013), and is not unduly or unreasonably preferential.

Decision:

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[354] ". . . that principle of equality does forbid any difference in charge which is not based upon difference in service, and, even when based upon difference of service, must have some reasonable relation to the amount of difference, and cannot be so great as to produce an unjust discrimination." *Laundry* at 45.

[355] *For example see, State ex rel. City of Joplin v. Pub. Serv. Comm'n,* 186 S.W.3d 290 (Mo. App. W.D. 2005).

[356] Ameren Missouri's fully allocated cost to serve Noranda would include an allocation of all fixed and variable costs. Noranda's current rate represents its fully allocated cost of service.

The Commission will start from a premise that no one really disputes; Noranda is significant to this state, to Ameren Missouri, and to its customers. Noranda's aluminum smelter near New Madrid, Missouri has a huge economic impact on a region of the state, known as the Bootheel, that is economically depressed. It buys staggeringly large amounts of electricity every hour of every day. It is by far Ameren Missouri's largest customer, by itself buying over ten percent of all the electricity Ameren Missouri sells.

For many years, Noranda has come before this Commission in every Ameren Missouri rate case and proclaimed that it needs low cost electricity to remain viable. Sometimes the Commission has made decisions that Noranda would find favorable; sometimes it has not. Most recently, less than a year ago, the Commission denied Noranda's request for a reduced rate in a complaint case decided while this case was pending. The Commission denied that request because Noranda failed to meet its burden of proof to show that its current rate was not just and reasonable. But Noranda continued its quest for a lower rate in this rate case, again asking for a rate that is below Ameren Missouri's fully allocated cost to serve. This time the Commission reaches a different result because additional evidence and argument was presented. The additional evidence describes a looming problem for Noranda: it must seek to refinance its existing debt in 2017 and 2019. Noranda presented various scenarios based on the price of aluminum in which it would run out of liquidity (cash and available credit) in the next few years. Those scenarios were criticized a not the most likely to occur, and indeed, they are not intended to be forecasts of aluminum prices. Rather, they are scenarios of what would happen if aluminum prices, which are volatile, were to drop. They are worst case scenarios, but sometimes the worst happens.

Lenders do not look at a borrower and accept promises that everything will be alright if aluminum prices stay as high as the analysts think they will. Investors asked to loan millions of dollars to Noranda will want to know whether the company will be able to survive and pay back its debts even if things do not go as well as planned. Therefore, lenders will stress test the company by looking at unfavorable scenarios. Wall Street agrees that Noranda has a problem as the company's credit rating was recently downgraded to a highly speculative grade of risk. Unless Noranda's cash flow improves, it will likely be unable to refinance its debt and could be forced to close.

In this case, Noranda and the other parties presented evidence sufficient to convince the Commission that Noranda is in danger of discontinuing operations at its New Madrid smelter in the absence of a load retention rate. As a result, it is in the interest of all ratepayers for the Commission to allow Noranda a lower rate to keep it as a customer of Ameren Missouri.

In part, Noranda's precarious financial situation is the result of Apollo Management's decision to milk massive amounts of cash out of the company when it purchased it in 2007. Certainly, Noranda would be better off today if it still had the hundreds of millions of dollars that Apollo borrowed against the assets of the company to give to itself as a special dividend. Apollo no longer owns all the shares of Noranda, but it still owns a third of its shares and can influence its board of directors.

The Commission is not tasked with protecting private interests, and it does not want to reward Apollo's behavior in any way, but it must protect the public interest and set just and reasonable rates. In these circumstances, the public interest encompasses more than the economic concerns of Noranda's employees, the Bootheel, or even the state of

Missouri. Specifically, and of greatest import to this Commission's mandate, is the effect of Noranda's closure on Ameren Missouri's other customers. It is important to understand that a customer in St. Louis who has no connection to the Bootheel, will pay higher electric rates if Noranda closes its smelter. Right now, Noranda pays a large portion of Ameren Missouri's fixed costs, costs that will not go away just because Noranda no longer buys electricity. If Noranda closes its smelter, those costs will still be there, but then all Ameren Missouri's other customers will have to pick up the bill for those fixed costs. Thus, Ameren Missouri's other customers will benefit from retaining Noranda's load for Ameren Missouri.

As with everything else involving Noranda, the numbers are large. Noranda argues that the incremental cost to provide power to Noranda, that is the price at which Ameren Missouri could sell that power on the off-system market, is approximately $28 per MWh. If Noranda pays a rate of $36 per MWh and buys 4 million MWhs per year, it would contribute roughly $32 million per year towards Ameren Missouri's fixed costs. That is $32 million per year that Ameren Missouri's other customers will have to pay if the smelter shuts down. Even if it is assumed that the incremental cost is $31.50 per MWh as estimated by Staff, Noranda would still be contributing $18 million per year to Ameren Missouri's fixed costs at a rate of $36 per MWh. It is true Ameren Missouri's other customers will have to pay extra to make up for the lower rate given to Noranda. But they will have to pay even more if the smelter shuts down and Noranda contributes nothing to Ameren Missouri's fixed costs.

During the hearing, Noranda and several consumer groups, including the Public Counsel, filed a non-unanimous stipulation and agreement to which several parties objected. Because the stipulation and agreement is not unanimous, the Commission cannot approve it. However, the stipulation and agreement remains the joint position of the signatory parties and the Commission can use it as a starting point toward crafting a revised rate for Noranda.

The non-unanimous stipulation and agreement - now the joint position - has some good features, but the Commission is not willing to adopt that position in its entirety. First, the $34 per MWh rate proposed is too low. The Commission wants to ensure that Noranda remains competitive with other smelters in this country but does not want to require other customers to support a rate for Noranda that would make it the lowest overall cost smelter in the country.

Second, the ten-year term of the joint position is too long, and is largely illusory. Ten years is a very long time, and the market for electricity may look very different by that time. Attempting to set a rate at that distance, even with escalator clauses and opt-out measures, would not be prudent. Additionally, while a stipulation and agreement can be binding on its signatories for ten years, the Commission cannot bind future Commissions, nor can it preclude future litigants from presenting contrary positions in future rate cases, positions to which the Commission will need to give due consideration.

Since the Commission cannot, and will not, approve the joint position in its entirety, it will need to explain in detail the rate that will be established for service to Noranda:

1. For a period of three years, a new class of Ameren Missouri electric service ratepayer is authorized for Industrial Aluminum Smelters (IAS).
2. The existing tariff and rates for the LTS class will remain in effect and will be updated in this and future rate cases. If Noranda is not willing to accept the terms of service for the IAS class, or if it violates the conditions

set forth in this order, it shall revert to the LTS class.

3. An effective base rate of $36.00 per MWh is set for the IAS class, to become effective when new rates go into effect resulting from this case.
4. The new IAS class shall remain subject to the Rider FAC, but any increase in rates due to operation of the Rider FAC shall not exceed $2.00 per MWh.
5. The IAS class will not be subject to any rate increase resulting from this case.
6. If Ameren Missouri files any additional rate cases during the three-year existence of the IAS class, it is the intent of this Commission that the IAS class shall receive 50 percent of the system average increase and zero percent of any system average decrease resulting from such rate cases. When the FAC is rebased in such rate proceeding, the IAS shall once again be subject to no more than a $2.00 per MWh rate increase due to the Rider FAC. The intent of this Commission is not binding on a future Commission, and such future Commission must decide those cases based on the competent and substantial evidence presented in those cases.
7. The IAS class may retain its existence and rate after the expiration of the three-year term until such time as the Commission establishes a new rate in a general rate proceeding.
8. The IAS class shall be subject to 100 percent of any new surcharge, adjustment mechanism, or any other mechanism that seeks to change or

impose new rates between rate cases that takes effect during the three-year term as a result of any new Missouri legislation passed and taking effect after the implementation date of rates resulting from this case.

9. The new IAS class shall not be subject to charges, rates, or surcharges that were not in effect at the implementation date of rates resulting from this case unless specifically enumerated in this order.

10. The resulting deficiency in retail base rate revenue associated with the creation of the IAS class shall be applied among all remaining classes paying for Ameren Missouri's electric service by changing base rate revenue in proportion to current base rate revenue minus LTS base rate revenue. Any change in FAC revenues associated with the rate for the IAS class shall flow automatically through the FAC to all remaining classes paying for Ameren Missouri's electric service.

11. As a condition to access the reduced rate structure available to the IAS class, the IAS customer shall provide the Commission's Staff and all parties to this rate case the following information regarding employment at the New Madrid smelter:

    The IAS customer shall file a monthly certification of compliance and quarterly surveillance reports demonstrating that the customer has fulfilled the requirement that employment at the New Madrid smelter meets or exceeds a daily average of 850 full-time equivalent personnel, either direct employees or contract personnel, and specifically noting instances where the employee count goes below the required average because employees have voluntarily left the customer's employ and the IAS customer is actively seeking to fill those positions, or due to *force majeure* or other events considered by the Commission to be outside the IAS customer's control.

The information provided shall be classified as Highly Confidential.

12. As a condition to access the reduced rate structure available to the new IAS class, and the limited exemption from the FAC, the IAS customer shall expend $35 million in capital, as defined by accounting principles generally accepted in the United States (USGAAP), at the New Madrid smelter in the first year of the term, and shall provide the Commission Staff and all parties to this rate case an annual surveillance report, which shall be designated as Highly Confidential, detailing the nature and scope of work performed to meet the $35 million requirement with discrete expenditures accounted for by amount of capital expended.
13. As a condition to access the reduced rate structure available to the new IAS class, and the limited exemption from the FAC, after the first year of the term and through the period that the reduced base rate is in effect, the IAS customer shall expend an annual inflation adjusted $35 million in capital as defined by USGAAP at the New Madrid smelter, utilizing the general Consumer Price Index as published by the US Bureau of Labor Statistics, compounded annually, in the second through final years the reduced base rate is in effect, and a pro-rated inflation-adjusted monthly capital expenditure for each full months the reduced base rate is in effect

after the term to the extent there are any partial-year terms, and to provide the Commission Staff and all parties to this rate case an annual surveillance report, which shall be designated Highly Confidential, detailing the nature and scope of work the customer performed to meet the required aggregate capital investment level with discrete expenditures accounted for by amount of capital expended.

14. The IAS customer may elect to invest an amount greater than $35 million in capital per year, as defined above, as set forth in paragraphs 12 and 13, with a corresponding reduction in its capital spending obligation in the later years of this period, but in no event shall the IAS customer's capital investment spending credited at the end of each year be less than the compounded inflation-adjusted expenditure requirement for that same period as set forth in paragraphs 12 and 13.
15. As a condition to access the reduced rate structure available to the IAS class, and the limited exemption from the FAC, the IAS customer shall not issue any special dividend, aside from its regular, customary penny per share dividend, until after the first rate case following the expiration of the three-year term.
16. The IAS customer may remain in the IAS class only so long as it remains a stand-alone entity. Membership in the IAS class shall not be assigned to, or assumed by, any successor company, whether through direct ownership, through a holding company, or otherwise unless such assignment or assumption is approved by the Commission.

17. If the IAS customer believes that it will have to discontinue operations at the New Madrid smelter, it shall provide notice to the Commission and to all parties to this case without delay and as soon as reasonably possible.
18. As a term of the IAS tariff, if the IAS customer should materially fail – as determined by the Commission – to comply with any term or condition required to access the reduced rate provided by this order, the IAS customer shall no longer have access to the rate structure outlined herein, and the customer's rate structure shall revert to the rate structure set for the LTS class at that time, with the resulting difference in retail revenue to be allocated to the benefit of the remaining customer classes in equal proportion to their then-current contribution to retail revenue less the LTS class. Since Ameren Missouri's rates to other customers cannot be changed except through a general rate case, Ameren Missouri shall retain the extra payments collected from Noranda in that event in a regulatory liability to be returned to customers with interest in Ameren Missouri's next general rate case.
19. The Commission Staff or any party to this case may file a petition asking the Commission to determine whether the IAS customer has failed materially to comply with any term or condition required to access the reduced rate structure. Upon the filing of such a petition, the Commission shall hold a hearing or make a determination based on verified pleading within 30 days of the filing of the petition.
20. At such a hearing, the IAS customer shall bear the burden to show that it

has not failed to meet any term or condition required to access the IAS class rate structure; why its failure to meet any term or condition required to access the IAS class rate structure is immaterial; or why it should continue to access the IAS class rate structure despite a material failure to meet any term or condition required to access the IAS class rate structure.

21. In assessing whether a violation of any term or condition is material, the Commission shall weigh all relevant factors, including:

(a) Any evidence of *force majeure*;

(b) With regard to an alleged violation of an employment level condition, whether the violation is the *de minimis* result of the quarterly-average calculation and whether the IAS customer has actively sought, or is actively seeking, to fill those vacant positions.

In future rate cases, the Commission will once again assess whether Noranda should be allowed to continue to receive a reduced load retention rate, and may continue this rate and these conditions as it finds appropriate based on the competent and substantial evidence presented in such cases, including the economic conditions at the time of that case. In such future rate case, the Commission would consider extending the term of the special rate with additional conditions and consumer protections, including a possible price trigger based on aluminum prices on the London Metals Exchange.

THE COMMISSION ORDERS THAT:

1. The tariff sheets filed by Union Electric Company, d/b/a Ameren Missouri on July 3, 2014, and assigned tariff number YE-2015-0003, are rejected.

2. Union Electric Company, d/b/a Ameren Missouri is authorized to file a tariff sufficient to recover revenues as determined by the Commission in this order.

3. Union Electric Company, d/b/a Ameren Missouri shall file the information required by Section 393.275.1, RSMo 2000, and Commission Rule 4 CSR 240-10.060 no later than May 15, 2015.

4. The Department of Economic Development's Petition for Leave to File Amicus Brief is denied.

5. This report and order shall become effective on May 12, 2015.

BY THE COMMISSION

Morris L. Woodruff
Secretary

R. Kenney, Chm., W. Kenney, Hall, and
Rupp, CC., concur;
Stoll, C., dissents, with separate dissenting opinion attached.

Dated at Jefferson City, Missouri,
on this 29th day of April, 2015.

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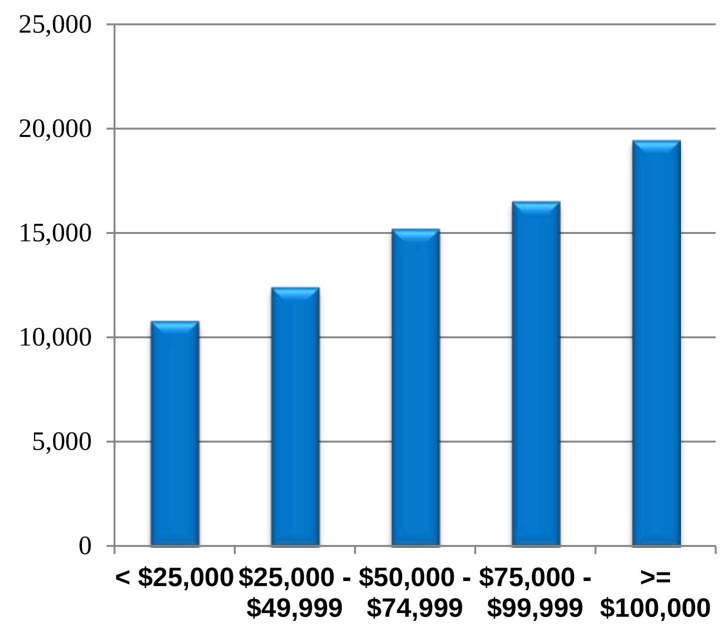
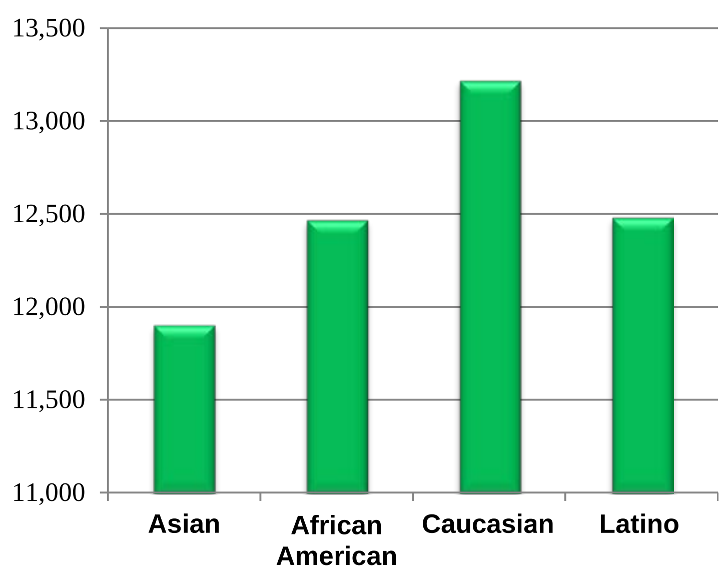
UTILITY RATE DESIGN:
HOW MANDATORY MONTHLY CUSTOMER FEES CAUSE DISPROPORTIONATE HARM

U.S. REGION: FL

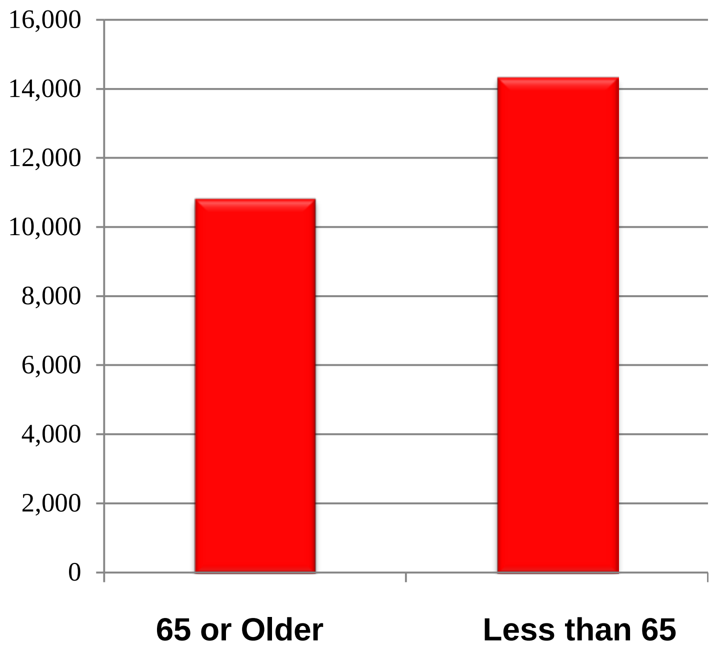
Median 2009 Residential Electricity Usage (KWH), by Income



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

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John A. Tuma	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota

ISSUE DATE: May 8, 2015

DOCKET NO. E-002/GR-13-868

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

Contents

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FINDINGS OF FACT, CONCLUSIONS, AND ORDER

PROCEDURAL HISTORY

I. Initial Filings and Orders

On November 4, 2013, Northern States Power Company d/b/a Xcel Energy (Xcel or the Company) filed this general rate case. The Company asked to increase Minnesota retail electric rates in 2014 by some $192,708,000, or 6.9%, and by an additional $98,535,000, or 3.5%, in 2015; combined, these proposals would increase Xcel's Minnesota revenues by a total of $291,243,000 per year, or approximately 10.4%. The filing included a proposed interim rate schedule.

On the same date, the Company filed a petition to establish a new base cost of energy for the period during which interim rates would be in effect; that petition was granted by order dated January 2, 2014.[1]

Also on January 2, 2014, the Commission issued three orders in this case:

- an order finding the rate-case filing substantially complete and suspending the proposed final rates;
- a notice and order for hearing referring the case to the Office of Administrative Hearings for contested-case proceedings; and
- an order setting interim rates for the period during which the rate case was being resolved.

[1] *In the Matter of the Petition of Northern States Power Company for Approval of a New Base Cost of Energy*, E-002/MR-13-869.

II. The Parties and Their Representatives

The following parties appeared in this case:

- Northern States Power Company d/b/a Xcel Energy (Xcel or the Company), represented by Aakash H. Chandarana, Kari L. Valley, James R. Denniston, and Stephen E. Fogel, all of Xcel Energy Services Inc.; and Richard J. Johnson and Patrick T. Zomer, Moss & Barnett, P.A.

- Minnesota Department of Commerce (Department) represented by Linda S. Jensen, Peter E. Madsen, and Julia E. Anderson, Assistant Attorneys General.

- Office of the Minnesota Attorney General–Residential Utilities and Antitrust Division (OAG), represented by Ian Dobson and Ryan Barlow, Assistant Attorneys General.

- Suburban Rate Authority, represented by James M. Strommen, Kennedy & Graven, Chartered.

- Flint Hills Resources, LP; Gerdau Ameristeel US Inc.; Unimin Corporation; and USG Interiors, Inc. (collectively, the "Xcel Large Industrials"), represented by Andrew P. Moratzka and Sarah Johnson Phillips, Stoel Rives LLP.

- Minnesota Chamber of Commerce (Chamber), represented by Richard J. Savelkoul, Martin & Squires, P.A.

- U.S. Energy, Inc. on its own behalf and on behalf of an ad hoc group of its industrial, commercial, and institutional customers (collectively, "the ICI Group"), represented by Peder A. Larson and Connor T. McNellis, Larkin, Hoffman, Daly & Lindgren, Ltd.

- The "Commercial Group," an ad hoc association of large commercial customers, including JC Penney Corporation, Inc.; Macy's, Inc.; Sam's West, Inc.; and Wal-Mart Stores, Inc., represented by Alan R. Jenkins, Jenkins at Law, LLC.

- Energy CENTS Coalition (ECC), represented by Pam Marshall, Executive Director.

- Fresh Energy, Izaak Walton League–Midwest Office, Sierra Club, and Minnesota Center for Environmental Advocacy, represented by Kevin Reuther, Legal Director, Minnesota Center for Environmental Advocacy; and Natural Resources Defense Council, represented by Samantha Williams, Attorney at Law, Natural Resources Defense Council (collectively, "Clean Energy Intervenors").

- AARP, represented by John B. Coffman, John B. Coffman, LLC.

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Jeanne M. Cochran to hear the case.

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings. The ALJ held evidentiary hearings in Saint Paul on August 11–15, 2014. After the hearings the parties filed initial briefs, reply briefs, and proposed findings of fact.

The ALJ also held seven public hearings in the case, on the dates and at the locations set forth below:

- Earle Brown Heritage Center, Minneapolis—June 23
- Sabathani Community Center, Minneapolis—June 23
- West Minnehaha Recreation Center, Saint Paul—June 24
- Woodbury Central Park, Woodbury—June 24
- Civic Center, Mankato—June 25
- Eden Prairie City Center, Eden Prairie—June 26
- Lake George Municipal Complex, St. Cloud—June 27

IV. Public Comments

The Administrative Law Judge held seven public hearings. Representatives of the Company, the Department, the Office of the Attorney General, the Commission, AARP, the Clean Energy Intervenors, and the Suburban Rate Authority attended.

Some 90 members of the public spoke at the public hearings, and over 900 members of the public filed written comments; the vast majority were residential customers. The Administrative Law Judge categorized and summarized the public comments in a 14-page attachment to her report.

Nearly all commenting members of the public either opposed the rate increase entirely or argued that it was too high. The objections raised most frequently were that the increase would cause hardship for low-income households, that the amount of the increase should not exceed the inflation rate or the latest Social Security cost-of-living adjustment, that customers' conservation efforts were not being rewarded and might therefore be discouraged, and that the Company was not controlling costs sufficiently, especially in the area of executive compensation.

Several commenting parties specifically objected to the proposed increase in the residential customer charge, arguing that it reduced conservation incentives and disproportionately affected low-income households. There was widespread opposition to the Company's proposal to increase residential rates by a higher percentage than commercial and industrial rates, with commenters arguing that business customers were better able to absorb rate increases.

Several members of the public supported the Company's revenue decoupling proposal, believing that removing the link between Company revenues and energy sales would increase its openness to conservation, energy efficiency, and rooftop solar installations by customers. Public opinion was divided on the Clean Energy Intervenors' proposal to establish inclining-block rates, under which per-unit rates would increase with a customer's total usage. Opinion was similarly divided on which generation resources—e.g., fossil fuel, nuclear, renewable—should be favored and under what time frames.

Several members of the public raised service-quality concerns, while others praised the service quality in their neighborhoods. Several commenters opposed allocating to ratepayers any portion of cost overruns incurred in recent nuclear upgrade projects undertaken by the Company. Several commenters proposed institutionalizing rate discounts for low-income senior citizens, low-income households generally, and customers making substantial contributions to state energy-policy and environmental objectives.

All public comments are filed in the case record. Written comments are labeled "Public Comment," and oral comments appear in the public-hearing transcripts filed by the court reporter.

V. Proceedings Before the Commission

On December 26, 2014, the Administrative Law Judge filed her Findings of Fact, Conclusions of Law and Recommendations (the ALJ's Report). The following parties filed exceptions to the ALJ's Report under Minn. Stat. § 14.61 and Minn. R. 7829.2700: the Company, the Department, the OAG, the Xcel Large Industrials, the Minnesota Chamber of Commerce, the ICI Group, the Clean Energy Intervenors, and AARP.

On March 19 and 26, 2015, the Commission heard oral argument from and asked questions of the parties. On March 26, 2015, the record closed under Minn. Stat. § 14.61, subd. 2.

Having examined the entire record in this case, and having heard the arguments of the parties, the Commission makes the following findings, conclusions, and order.

FINDINGS AND CONCLUSIONS

I. The Ratemaking Process

A. The Substantive Legal Standard

The legal standard for utility rate changes is that the new rates must be just and reasonable.[2] The Minnesota Supreme Court has described the Commission's statutory mandate for determining whether proposed rates are just and reasonable as "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers," citing Minn. Stat. § 216B.16, subd. 6.[3] That statute is set forth in pertinent part below:

> The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.

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[2] Minn. Stat. § 216B.16, subds. 4, 5, and 6.

[3] *In re Interstate Power Co.*, 574 N.W.2d 408, 411 (Minn. 1998).

B. The Commission's Role

While the Public Utilities Act provides baseline guidance on the ratemaking treatment of different kinds of utility costs, it generally makes only threshold determinations on rate recoverability, leaving to the Commission the tasks of determining (a) the accuracy and validity of claimed costs; (b) the prudence and reasonableness of claimed costs; and (c) the compatibility of claimed costs with the public interest.

In ratemaking, therefore, the Commission must decide a wide range of issues, ranging from the accuracy of the financial information provided by the utility, to the prudence and reasonableness of the underlying transactions and business judgments, to the proper distribution of the final revenue requirement among different customer classes.

These diverse issues require different analytical approaches, involve different burdens of proof, and require the Commission to exercise different functions and powers. In ratemaking the Commission acts in both its quasi-judicial and quasi-legislative capacities: As a quasi-judicial body it engages in traditional fact-finding, and as a quasi-legislative body it applies its institutional expertise and judgment to resolve issues that turn on both factual findings and policy judgments. As the Supreme Court has explained,

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.[4]

C. The Burden of Proof

Under the Public Utilities Act, utilities seeking a rate increase have the burden of proof to show that the proposed rate change is just and reasonable.[5] Any doubt as to reasonableness is to be resolved in favor of the consumer.[6]

On purely factual issues, the Commission acts in its quasi-judicial capacity and weighs evidence in the same manner as a district court, requiring that facts be proved by a preponderance of the evidence. On issues involving policy judgments, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.

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[4] *In re N. States Power Co.*, 416 N.W.2d 719, 722–23 (Minn. 1987) (citation omitted).

[5] Minn. Stat. § 216B.16, subd. 4.

[6] Minn. Stat. § 216B.03.

Utilities seeking rate changes must therefore prove not only that the facts they present are accurate, but that the costs they seek to recover are rate-recoverable, that the rate recovery mechanisms they propose are permissible, and that the rate design they advocate is equitable, under the "just and reasonable" standard set by statute. As the Court of Appeals explained, quoting the Supreme Court,

> A utility seeking to change its rates has the burden of proving by a preponderance of the evidence that its proposed rate change is just and reasonable. Minn. Stat. § 216B.16, subd. 4 (1986). "Preponderance of the evidence" is defined for ratemaking proceedings as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[7]

II. Rate Case Overview

A. Capital Expenses

Xcel states that its request for a rate increase is motivated by being "in the peak years of an investment cycle that began several years ago." The Company plans significant capital investment in 2014 and 2015 that it believes necessary to provide safe, reliable electric service to its Minnesota customers. It initially identified 733 projects for 2014 representing approximately $954,000,000 of capital additions, and another 116 projects for 2015 representing just over $932,000,000 of capital additions.

B. Multiyear Rate Plan Proposal

The Company proposed a multiyear rate plan, the first of its kind in Minnesota since they were authorized by the Legislature in 2011. The Company explained that its goal was to provide more gradual rate increases and predictable bill impacts.

Minn. Stat. § 216B.16, subd. 19, authorizes the Commission to approve multiyear rate plans. A multiyear rate plan establishes the rates a utility may charge for each year of a specified period of years (not to exceed three years), based only on the utility's reasonable and prudent costs of service over the term of the plan.

The statute also authorizes the Commission to establish the terms, conditions, and procedures for such plans, which it did by order on June 17, 2013.[8] The Commission established that utilities may propose a multiyear rate plan to improve the regulatory process for recovery of (a) costs related to specific, clearly identified capital projects, and (b) appropriate non-capital costs.[9]

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[7] *In re Minn. Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. App. 1989) (citation omitted).

[8] *In the Matter of the Minnesota Office of the Attorney General–Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans Under Minn. Stat. § 216B.16, subd. 19*, Docket No. E,G-999/M-12-587, Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans (June 17, 2013) (the Multiyear Rate Plan Order).

[9] Multiyear Rate Plan Order at 12.

The Company requests that the Commission establish rates based on a 2014 test-year revenue requirement, and adjust them for a 2015-Step increase to incorporate specified 2015 capital projects and related non-capital costs.

Because this is the first opportunity for the Commission to consider a multiyear rate plan proposal, several issues are presented for Commission consideration for the first time. These issues are identified and discussed in greater detail, below.

C. Multiyear Rate Plan Refund Mechanism

During the evidentiary hearing, Xcel proposed a refund mechanism as part of the multiyear rate plan. The Company agreed to a process for refunding differences between 2014 and 2015 Commission-approved revenue requirements and actual revenue requirements associated with capital additions that are postponed or canceled.[10]

This proposal was resolved as agreed between the Company and the Department and was not presented as a disputed issue for resolution by the ALJ or the Commission.[11] The ALJ incorporated this refund mechanism into her recommendations.[12] The Commission finds the refund mechanism, generally, to be in the interest of ratepayers, has incorporated it into its decisions, and refers to it throughout this order.

III. Summary of the Issues

In its Notice and Order for Hearing the Commission directed the Company to address three issues unique to this case:

1) How to incorporate the results of a separate Commission investigation into the prudence of Xcel's expenditures for life-cycle management and an extended power uprate at its Monticello nuclear plant;

2) How to account for any insurance proceeds and litigation recoveries stemming from an accident at the Company's Sherburne County Generating Station Unit 3; and

3) How to determine the short-term and long-term consequences of rate-moderation mechanisms proposed in the Company's initial filing.

The first and last issues—pertaining to cost overruns at the Monticello nuclear plant and to the Company's proposals for moderating the rate impacts of this case—were contested and are discussed with the other contested issues listed below. The remaining issue—how to account for insurance proceeds and litigation recoveries resulting from an accident at the Company's Sherburne County Generating Station Unit 3 (Sherco 3)—is not yet ripe, since the Company's insurance claims and related litigation are not yet concluded.[13]

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[10] Subject to certain exclusions. *See* ALJ's Report at 17 n.81 and October 7, 2014 Issues List at 34–35.

[11] ALJ's Report, Attachment A at A-2.

[12] *See, e.g., id.* ¶ 90.

[13] *Id.*, Attachment A at A-3.

Many initially contested issues were resolved in the course of evidentiary proceedings. The Administrative Law Judge found that the resolutions reached by the parties were reasonable and supported by record evidence; she recommended accepting them.[14] The Commission concurs.

Other issues remained contested. The following issues were either contested or otherwise require discussion.

Financial Issues

- ***Ratemaking Treatment of Extended Power Uprate at Monticello Nuclear Plant***— Has the Company demonstrated that the Extended Power Uprate project, designed to increase generating capacity at its Monticello nuclear plant, meets the "used and useful" ratemaking standard for inclusion in the 2014 test year or the 2015 multiyear rate plan Step?

- ***Discount Rate and Treatment of 2008 Market Losses for Qualified Pension and Retiree Medical Expenses***—What is the appropriate discount rate, the interest rate used to adjust anticipated future benefits to present dollars, for the Company's qualified pension plan? Are cost increases attributable to the Company's 2008 market losses recoverable in rates?

- ***Total Labor Costs***—Has the Company demonstrated that the total labor costs built into test-year expenses are reasonable and prudent?

- ***Impact of Passage of Time on 2015-Step Revenue Requirement***—Should the Company's proposed 2015-Step increase reflect cost decreases attributable to the passage of time, especially reductions in depreciation expense?

- ***Delays in In-Service Dates for Capital Projects Included in 2015 Step***—Should the Company be permitted to substitute different capital projects for specific capital projects included in the test year or 2015 Step when delayed in-service dates make them ineligible for inclusion?

- ***Treatment of Nuclear-Refueling-Outage Costs in the 2015 Step***—Should the 2015-Step revenue requirement be adjusted to reflect a one-year decrease in nuclear-refueling-outage costs?

- ***Carrying Charge on Nuclear-Refueling-Outage Costs***—Should the Company continue to recover a carrying charge on unamortized nuclear-refueling-outage costs?

- ***Costs of Cancelled Extended Power Uprate at Prairie Island Nuclear Plant***—To what extent, if any, should the Company be permitted to recover the costs of its cancelled project to expand the generating capacity of its Prairie Island nuclear plant?

- ***Method of Recovering Pleasant Valley and Border Winds Wind-Farm Costs***—Should the capital costs of these wind farms be recovered through base rates or the Renewable Energy Standard rider?

[14] *Id.*, Conclusion of Law 5.

- ***Nuclear-Depreciation-Reserve Surplus*****—**What is the magnitude of the Company's nuclear-depreciation-reserve surplus and should amortization of any portion of it be required?

- ***Corporate Aviation*****—**Has the Company demonstrated that the corporate-aviation costs included in test-year expense are reasonable and prudent?

- ***Key Performance Indicator Relating to Transmission Operation and Maintenance Costs*****—** Should the Company be required to add a new key performance indicator to its incentive-compensation program relating to transmission operation and maintenance (O&M) costs, supported by a comparison study of the transmission O&M costs of peer utilities?

- ***CWIP and AFUDC*****—**Should the Company be permitted to continue placing Construction Work in Progress in rate base and offsetting Allowance for Funds Used During Construction from the income statement?

- ***Fuel-Clause Concerns*****—**Should the Commission require the Company to propose a new cost-of-fuel recovery mechanism on a timeline set in this order?

- ***Replacement-Power Costs Caused by Sherco 3 Outage*****—**Should the ratemaking treatment of purchased-power costs incurred to replace the power lost in the Sherco 3 outage be addressed in this rate case or in the annual fuel-clause-adjustment case?

- ***Costs of December 2012–March 2013 Outage at Black Dog Units 2 and 5*****—**Should the Commission address the costs of this three-month outage in this rate case?

- ***Babcock & Wilcox Litigation*****—**How should the Commission address the Company's inclusion in test-year costs of some $46,000,000 in unpaid capital costs that are being litigated and potentially subject to substantial interest charges?

- ***Rate-Moderation Proposals*****—**Should either of the Company's two rate-moderation proposals be adopted? (These proposals are to apply portions of the nuclear-waste settlement reached with the U.S. Department of Energy to rate relief and to accelerate the amortization ordered in the last rate case of the surplus in the Company's transmission, distribution, and general depreciation reserve.)

Cost of Capital Issues

- ***Return on Equity*****—**What is a fair and reasonable return on equity for this company, on this record, at this time?

Class Cost of Service Study (CCOSS) Issues

- ***Classifying Fixed Production Plant*****—**Does the Company's use of the plant-stratification method in its CCOSS properly allocate the costs of its fixed production plant between capacity and energy?

- ***Classifying Fixed Production Plant in Wind Facilities—***Does the Company's classification of two wind facilities as 100% capacity-related properly allocate the fixed production plant of these facilities?

- ***D10S Capacity Allocator—***Does the Company's D10S allocator properly allocate capacity-related fixed production plant costs among the customer classes?

- ***Classifying Other Production Operation and Maintenance Costs—***Does the Company's CCOSS properly allocate production-plant O&M costs other than fuel and purchased power between capacity and energy?

- ***Minimum System Study—***Does the Company's minimum-distribution-system study properly classify distribution costs as customer-related or capacity-related?

<u>Rate Design Issues</u>

- ***Decoupling—***Should the Company be permitted to implement a decoupling rate design and, if so, under what terms and conditions?

- ***Class Revenue Apportionment—***What percentage of the revenue requirement should be allocated to each customer class?

- ***Method of Recovering CIP Costs—***Should the Company stop recovering its Conservation Improvement Program costs through base rates, subject to true-up through a rate rider, and start recovering them entirely through a rate rider?

- ***Residential and Small-General-Service Customer Charges***—At what level should the Commission set the fixed monthly charge for residential and small-general-service customers?

- ***Interruptible-Service Discounts***—What are the appropriate discounts for customers who agree to accept risks of disconnection that vary in terms of maximum hours disconnected, minimum notice of disconnection, length of contract term, and other factors?

- ***Inclining-Block Rates***—Should the Commission open a new docket to explore the conservation potential and public-interest implications of an inclining-block rate design for the Company's residential class?

- ***Coincident-Peak Billing***—Should the Company be required to permit synchronized interval-by-interval aggregated demand billing for all metered locations on a single business site, including meters on contiguous properties?

- ***Defining "Contiguous"—***Should the Company be required to incorporate a statutory definition of "contiguous property" into its tariff?

- ***Renewable-Energy-Purchase Tariff***—Should the Company be required to work with stakeholders and present in its next rate case a proposal for pairing large high-load-factor customers operating 24 hours per day with renewable energy resources available primarily during off-peak hours?

These issues are examined individually below, with issues on which the Commission declines to accept the ALJ's recommendation discussed in greater detail.

IV. The Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held five days of formal evidentiary hearings and seven public hearings. She reviewed the testimony of 54 expert witnesses and related hearing exhibits. She heard testimony from 90 members of the public and read some 900 written comments submitted by members of the public.

The ALJ received and reviewed initial and reply post-hearing briefs from the parties, as well as their proposed findings of fact and conclusions of law. She made 1,032 findings of fact and conclusions of law and made recommendations on all stipulated, settled, and contested issues based on those findings and conclusions.

The Commission has itself examined the record, considered the report of the Administrative Law Judge, considered the exceptions to that report, and heard oral argument from the parties. Based on the entire record, the Commission concurs in most of the Administrative Law Judge's findings and conclusions. On some issues, however, the Commission reaches different conclusions, as delineated and explained below. And on a few issues it provides technical corrections and clarifications.

On all other issues, the Commission accepts, adopts, and incorporates the ALJ's findings, conclusions, and recommendations.

FINANCIAL ISSUES

V. Ratemaking Treatment of Extended Power Uprate at Monticello Nuclear Plant

A. Introduction

1. The Monticello LCM/EPU Project

The Monticello Nuclear Power Generating Plant (Monticello or the plant) has been operating since 1971 and was initially licensed to operate until 2010.

In 2006, Xcel obtained a license extension from the federal Nuclear Regulatory Commission (NRC) to continue operating the plant until 2030. In 2008, the Company requested a license amendment from the NRC to increase, or "uprate," the plant's generating capacity from 600 to 671 megawatts (MW) and applied to this Commission for a certificate of need for the uprate. Xcel stated that it would achieve the additional 71 MW by increasing the amount of steam produced in the reactor and by improving plant equipment that converts steam into electricity.

In January 2009, this Commission granted the certificate of need for the additional generating capacity at Monticello.[15] Xcel began a project to (a) extend the useful life of the plant (the Life-Cycle Management, or LCM, portion) and (b) increase its generating capacity (the Extended Power Uprate, or EPU, portion). In its certificate-of-need application, the Company estimated that $133 million of the anticipated $320 million project cost, or 41.6%, could be attributed to the EPU.

Xcel planned to implement the LCM/EPU project in phases timed to correspond to scheduled refueling outages in 2009 and 2011. During implementation, however, the Company discovered the need for a series of modifications that forced it to delay some of the installation work until the 2013 outage and caused significant cost overruns.

2. Xcel's 2012 Rate Case

Xcel first sought to recover Monticello LCM/EPU project costs of $587 million in its 2012 rate case. At that time, the NRC had not yet granted a license amendment authorizing the Company to operate the plant at the higher EPU power level. As a result, the plant was running at its licensed 600 MW capacity using the improved equipment intended to accomplish both the LCM and the EPU aspects of the plant upgrade.

Because Monticello was not yet operating at the uprate level, the Commission found that only the LCM portion of the project was used and useful and required Xcel to remove 41.6% of the project costs from rate base, based on the Company's estimated EPU allocation in the 2008 certificate-of-need application.[16] The Commission stated that Xcel could seek recovery of those costs in future rate cases once the EPU was in service.

3. Xcel's 2013 Rate Case

Two months after the Commission decided its 2012 rate case, Xcel filed this rate case. The Company requested recovery of $665 million in Monticello LCM/EPU costs, stating that it expected to receive the NRC license amendment for the EPU during the 2014 test year.

In early 2014, Xcel obtained the necessary NRC license approvals and began a "power ascension process" at the plant under the NRC's supervision. Under the power-ascension process, a plant's capacity is gradually increased, and data is sent to the NRC for review at predefined power levels. The plant cannot ascend to the next predefined power level without NRC approval.

On March 11, 2014, Monticello reached the first NRC data-collection level, which was approximately 640 MW. After reviewing the data, Xcel discovered an anomaly with the steam-dryer data. As a result, and to comply with its license, on March 27, 2014, the Company returned the plant to its pre-EPU level of 600 MW.

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[15] *In the Matter of the Application of Northern States Power Company for a Certificate of Need for the Monticello Nuclear Generating Plant Extended Power Uprate*, Docket No. E-002/CN-08-185, Order Granting Certificate of Need and Accepting Environmental Assessment (January 8, 2009).

[16] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order at 19 (September 3, 2013).

The plant remained at pre-EPU levels throughout the spring and summer of 2014 while Xcel reviewed the data and responded to follow-up questions from the NRC. As of the August 11, 2014 evidentiary hearing in this case, the NRC had not yet completed its review of data from the first ascension level. The Company did not know when it would receive the NRC's approval to restart the ascension process but stated that it believed that it would be able to complete the process before the end of 2014.[17]

4. Monticello Prudence Investigation

Because of the significant cost overruns experienced at Monticello, in December 2013 the Commission opened a new docket to investigate whether Xcel's handling of the LCM/EPU project was prudent, whether the Company's request for recovery of cost overruns was reasonable, and which cost increases were due to (1) solely the EPU, (2) solely the LCM, and (3) both projects.[18] The Commission referred the investigation to an administrative law judge (ALJ) and requested that the ALJ complete the investigation in time to incorporate the results into this rate case.

The Commission issued its order concluding the prudence investigation concurrently with this order.[19] The Commission found that Xcel's management of the LCM/EPU was not prudent and denied the Company any return on the overrun, a disallowance that significantly impacts Xcel's revenue requirement in this rate case. The Commission also determined that 50% of the project costs were attributable to the LCM and that 50% were attributable to the EPU.

B. Positions of the Parties

The Department argued that the EPU was not "used and useful" because Xcel had never operated the EPU at its intended level of 71 MW, nor had the Company shown that the EPU was likely to become fully operational by the end of the 2014 test year. It argued that the EPU should not be considered used and useful until the NRC allows Xcel to operate Monticello at 671 MW. The Department recommended that the Commission exclude the EPU from rate base for 2014 and allow the project in rate base in the 2015 Step, subject to refund if the plant does not operate successfully at the uprate level by January 2015.

XLI agreed with the Department that Xcel had failed to meet its burden to show that the EPU was used and useful. XLI argued that there was no meaningful difference between the EPU's current status and its status at the time of the last rate case, since the Company was unable to operate Monticello at the full 671 MW uprate level on an ongoing basis. XLI therefore recommended that any EPU costs be excluded from rate base.

The Chamber agreed with the Department and XLI that the Monticello EPU was not currently used and useful. However, rather than excluding EPU costs from rate base, the Chamber proposed that the Commission leave the EPU in rate base but require Xcel to remove the 2014

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[17] In March 2015, during oral arguments before the Commission, Xcel stated that Monticello had ascended to 656 MW by the end of 2014, although the plant was not operating continuously at that level.

[18] *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life-Cycle Management/ Extended Power Uprate Project and Request for Recovery of Cost Overruns*, Docket No. E-002/CI-13-754, Order Approving Investigation and Notice and Order for Hearing (December 18, 2013).

[19] Docket No. E-002/CI-13-754, Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes.

depreciation expense and recover it over Monticello's remaining life. The Chamber also recommended that the increased fuel costs resulting from the delay in power ascension be returned to current ratepayers and instead be collected over the life of the plant.

Xcel argued that the EPU was used and useful based on several circumstances that had changed since the last rate case. First, the Company has received all necessary NRC license amendments to operate at EPU levels. Second, the LCM/EPU equipment is currently being used to produce power, resulting in higher safety margins and more efficient operation. And third, the plant achieved a partial uprate, ascending to 640 MW for approximately 20 days.

Xcel nonetheless accepted the Chamber's proposal to defer 2014 depreciation expense and fuel costs and to amortize them over Monticello's remaining life. The Company argued that the Chamber's proposal reasonably reflects the plant's current status while also recognizing the benefits that the upgraded plant provides to ratepayers.

C. The Recommendation of the Administrative Law Judge

Applying Minn. Stat. § 216B.16, subd. 6, the ALJ concluded that Xcel had failed to demonstrate that the EPU was in service and used and useful, or that it was likely to be so during the 2014 test year. The ALJ reasoned that, until the Company completes the EPU ascension process, ratepayers will not be able to receive the benefit of the additional 71 MW of power that the EPU was intended to provide, and the EPU will not be in service or used and useful.

Having found that the EPU was not used and useful during the test year, the ALJ recommended that the Commission adopt the Department's proposal to remove the EPU portion of the LCM/EPU project from 2014 rate base, and the associated depreciation expense from the 2014 test year. The ALJ recommended that Xcel be allowed to include the EPU costs in the 2015 Step subject to refund as part of the multiyear-rate-plan refund process.

Finally, the ALJ recommended rejecting the Chamber's proposed remedy. The ALJ reasoned that allowing Xcel a current return on the EPU and deferred recovery of 2014 depreciation expense would be inconsistent with the conclusion that the EPU was not used and useful during 2014. And she concluded that the increased fuel costs should be addressed in Xcel's Annual Automatic Adjustment (AAA) proceeding.

D. Commission Action

The Commission concurs in and adopts the Administrative Law Judge's findings, conclusions, and recommendations on this issue.

The Commission must consider the factors in Minn. Stat. § 216B.16, subd. 6, when determining what utility property should be included in Xcel's rate base. Specifically, the statute requires the Commission to consider a utility's need for revenue sufficient to enable it to meet the cost of furnishing service, "including adequate provision for depreciation of its utility property used and useful in rendering service to the public."

The Commission finds that the Monticello EPU was not used and useful in 2014. The circumstances of the EPU have not materially changed since the 2012 rate case. While Xcel did briefly bring the plant up to 640 MW in March 2014, as of the end of 2014 the Company still did not have the NRC's permission to operate Monticello at the full 671 MW uprate level. Thus, ratepayers are still not receiving the benefit for which Xcel is asking to be paid.

Because the Monticello EPU was not used and useful in 2014, the Commission will order that the 2014 depreciation expense and return on the EPU be excluded from the 2014 test year, based on the 50% LCM, 50% EPU allocation determined in the prudence-investigation docket. As recommended by the Department and the ALJ, the Commission will allow Xcel to recover EPU costs in the 2015 Step. However, if the EPU is not in service by January 1, 2015, the Company should refund any excess amounts collected in rates through the refund mechanism for the multiyear rate plan.

The disallowance of the 2014 depreciation expense for the Monticello EPU will be a permanent disallowance. Xcel should reduce Construction Work in Progress (CWIP) by this amount, or if the plant is shown as being included in Plant in Service, the disallowed depreciation expense should remain in the depreciation reserve, whichever is applicable. The Commission will direct the Company to make a compliance filing providing the accounting entries and explaining how this permanent disallowance is reflected in its accounting records.

Finally, there exists an increased cost of fuel due to Monticello's inability to produce power at 671 MW as planned. The Chamber argued that this increased cost should be accumulated and recovered from the ratepayers that benefit from the plant over its useful life. The Commission concurs with the ALJ that the issues raised by the Chamber—i.e., the amount of the increased cost, return to current ratepayers, and recovery from ratepayers benefitting from the EPU output—should be addressed in Xcel's Annual Automatic Adjustment proceeding.

VI. Qualified Pension Discount Rate

A. Introduction

Xcel described its employee retirement-income plan as a combination of defined-benefit pension and defined-contribution 401(k) plans. In its initial filing, the Company identified $19,933,516 in 2014 test-year qualified pension expenses, comprising $14,555,504 for its Northern States Power Company – Minnesota (NSPM) Plan and $5,378,012 for its Xcel Energy Services (XES) Plan. The Company arrived at the figures using different accounting methods for each plan. The Company uses the Aggregate Cost Method (ACM) for the NSPM Plan, and Financial Accounting Standard number 87 (FAS 87) methodology for the XES Plan.

Xcel and the Department disagree about the appropriate discount rate for the XES Plan. The lower the discount rate used in the calculation, the higher the calculated pension expense; the higher the discount rate, the lower the calculated pension expense. The ALJ recommended a discount rate for the XES Plan higher than the rate the Company initially recommended, and lower than the Department recommended.

B. Positions of the Parties

1. The Company

Xcel initially proposed to apply a discount rate of 4.74% for its XES Plan, the rate the Company calculated using the FAS 87 accounting standard. But following the contested case, Xcel accepted the ALJ's recommendation of 5.05%.

The Company argued that the ALJ's rationale and discount-rate recommendation were supported by the record and that the Commission should adopt the ALJ's proposed discount rate of 5.05% for the XES Plan. Xcel opposed the Department's proposal to set the XES Plan's discount rate equal to the rate of expected return on assets, arguing that doing so would result in under-recovery of pension costs.

2. The Department

The Department recommended setting the XES Plan's discount rate at 7.25% to match the plan's expected return on assets, and to match the discount rate applied over the same time period for the NSPM Plan. The Department argued that the pension-expense calculation for ratemaking purposes did not need to be governed by accounting practices implemented for another purpose, and that the discount rate applied to the two defined-benefit plans for the same time period should be the same. The Department also expressed concern that the figures used for financial accounting are "point-in-time" figures that generally change more frequently than rates, and challenged the reliability of the Company's supporting analysis.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended using a five-year average discount rate for the XES Plan, which results in a discount rate of 5.05%. The ALJ concluded that using a five-year average "is reasonable and strikes an appropriate balance" between the parties' positions.

The ALJ noted that, in the Company's 2012 rate case, the ALJ and the Commission adopted the Department's position. The ALJ recognized that the Company more thoroughly explained in this case the basis of its proposed discount rate. However, the ALJ still recommended a rate equal to the five-year average to mitigate the effect of a proposed discount rate "that is on the lower end of rates for the last five years."

D. Commission Action

The Commission will adopt the ALJ's recommendation for a 5.05% discount rate for the XES Plan. The calculation of pension expenses requires actuarial assumptions appropriate to the factual circumstances in each case. In this case, the Company has adequately explained the rationale for using different accounting methods, and different discount rates, for its XES and NSPM Plans. The Commission concludes that it is reasonable for ratemaking purposes to use the plans' different accounting methodologies as a basis for each plan's discount rate.

The Commission agrees with the Department that neither financial accounting standards nor pension funding requirements necessarily govern pension-expense calculations for ratemaking purposes. When the facts and circumstances support adopting a discount rate that differs from the rate dictated by accounting standards applied for other purposes, it is appropriate to adopt a rate that differs.

The appropriate discount rate varies, but changes are only reflected in utility rates periodically—when a rate case is decided. As the ALJ recognized, the Company's proposed discount rate is low relative to rates over the previous five years. For rate-setting purposes, in this case, it is appropriate to use a historical average to buffer the effect that the recently-below-average discount rate would have on the overall test-year pension expense. Under these conditions, a discount rate based on the five-year average is more reasonable than a discount rate determined at a single point in time.

The Commission also declines to adopt the following sentence from ALJ Finding 126: “For that reason, use of the FAS 87 bond-matching discount rate will help ensure that the XES Plan, which is subject to FAS 87, is fully funded.” While it is reasonable in this case to use the XES Plan’s FAS 87 accounting method to establish a reasonable discount rate, doing so does not ensure full funding of the Plan; absent Commission directives, pension funding is governed by federal law and company policy. Because the sentence overstates the effect of the discount-rate decision, it is not adopted by the Commission.

Certain XES Plan costs identified in the Company’s previous rate case have been deferred for recovery over time.[20] The Commission will require the Company to apply a rolling five-year average FAS 87 discount rate when determining XES Plan costs subject to deferral (or reversal) in subsequent years (i.e., non–rate-case test years) as the mitigation continues.

VII. Qualified Pension Market Loss

A. Introduction

In 2008, Xcel’s pension funds experienced a loss in value. Because of the accounting methods used by the Company, the losses did not begin to significantly affect its pension expense until its 2012 rate case. In that rate case, the Commission authorized Xcel to recover the amortized pension-fund losses identified in that case, but required that future recovery would be based on “[f]urther evaluation and evidence of the Company’s policy and practice pertaining to past and future pension policies, including surplus” to be provided in its next rate case.[21]

In this case, Xcel attributed most of the increase in its pension expense to amortized and phased-in 2008 market losses. The Company also introduced testimony describing its policy and practices related to accounting for pension market gains and losses. The Department disputed the continued presence and magnitude of 2008 market losses in the Company’s pension-expense-recovery proposal.

B. Positions of the Parties

1. The Company

Xcel argued that recovery of the 2008 market losses is reasonable. It stated that its practice of amortizing and phasing in market losses is both longstanding and consistent with pension accounting standards. It also clarified that the amount sought for recovery had been offset by market gains in the years since 2008, but that the magnitude of the losses means some losses have not yet been offset or recovered.

Xcel asserted that its accounting method for losses and gains is symmetrical, and that in previous years market gains resulted in pension expenses at or below zero between 2000 and 2011. It

[20] XES Plan costs were capped at 2011 levels in the Company’s previous rate case. See the discussion of qualified-pension-expense mitigation, below.

[21] Docket E-002/GR-12-961, Findings of Fact, Conclusions, and Order at 42 (September 2, 2013).

argued that denying amortized and phased-in recovery for market losses now would be asymmetrical. The Company also disputed the Department's suggestion that pension fund market gains since 2008 were unreasonably small.

2. The Department

The Department objected to full recovery of amounts attributable to the 2008 market loss. It argued that because the market has recovered substantially since 2008, the proposed recovery for 2008 market losses was extreme, should have been offset by market gains, and should not be passed along in its entirety to ratepayers. The Department recommended that the Commission reduce the approved recovery for 2008 market losses by 50%.

The Department also expressed concern about the performance of the pension funds, asserting that underperformance was at least partly responsible for the failure of market gains to substantially offset the 2008 losses.

C. The Recommendation of the Administrative Law Judge

The ALJ found that "the Company's treatment of the 2008 market loss is consistent with the Company's long standing practice of including both market gains and losses in its calculation of the pension expense." The ALJ recognized that the approach "results in a significant pension expense in the 2014 test year" but that in previous years ratepayers had received substantial benefits from the approach.

The ALJ concluded that excluding the losses now, when ratepayers had benefited from pension-expense relief during periods of market gains, would be unreasonable. The ALJ concluded that the Company's accounting method is reasonable, and that the proposed phase-in and amortization amount for the 2014 test year should be included.

Finally, the ALJ found no record support for the idea that the pension funds were imprudently invested, resulting in unreasonably low performance. She did not recommend reducing the pension expense on that basis.

D. Commission Action

The Commission agrees with the ALJ, and will not reduce the 2008-market-loss amount included in the test-year pension cost. The Commission determined in the Company's previous rate case that future recovery of amortized and phased-in losses as a component of pension expense would be subject to Commission review of the Company's policies and practices with regard to pension accounting. The Commission is satisfied with the Company's explanation.

As the Company explained, what has been characterized in this case as recovery for a 2008 market loss is actually the 2014 test-year portion of that substantial loss—an amount that is being phased in and amortized over a period of years consistent with ordinary and longstanding accounting practice—and is offset by gains in intervening years. The Commission agrees with the ALJ that treating losses and gains symmetrically in this way is reasonable.

The Commission also agrees that the Department's concern about pension-fund performance lacks record support and does not serve as a basis in this case to reduce the amount authorized for recovery. Higher market performance often comes with higher risk, and the record here is inadequate to conclude that the investment decisions made by the Company were unreasonable.

The effect of market volatility and investment risk on ratepayers, raised by the Department in this case, potentially affects all utilities. A generic Commission inquiry concerning pension discount rates is already under way.[22] To facilitate discussion of the issues raised by the Department, the Commission will expand that inquiry to include discussion on pension investment risk and rewards and ratepayer impacts.

Finally, because a well-performing pension fund provides some benefit to shareholders by reducing cash-flow needs, the Commission will revise ALJ Finding 157, as follows:

> 157. ~~Finally, contrary to the Department's assertion, there is no benefit to the shareholders from this longstanding approach to calculating pension expense because the Company~~ <u>The pension fund</u> does not pay out the gains to shareholders. Instead, the gains help to reduce rate increases by limiting the future pension expense. [citation omitted]

VIII. Qualified Pension Expense, Mitigation, and Future Filing Requirements

A. Introduction

The Company proposed two methods to decrease the effect of pension expense on rates in this case by postponing recovery. The proposals would not reduce the amount of revenue required to recover the pension-expense amounts, but defer a portion of the recovery to future years.

B. Positions of the Parties

1. The Company

Xcel suggested two ways to "normalize" pension-expense amounts to provide more certainty in the amount of an expense that can be affected by market swings and other factors. Both methods involved authorizing an expense amount based on an average of a five-year forecast, annual tracking of the difference between the authorized amount and actual (or forecast) expense amounts, and a Commission determination in the future about how to handle the difference between the two.

The Company offered these proposals in addition to agreeing that the normalization approach adopted in its last rate case is acceptable. In the Company's 2012 rate case, it proposed extending the amortization of pension expenses for the NSPM Plan from 10 to 20 years, and capping expenses of the XES Plan at 2011 levels.

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[22] A docket number has not yet been assigned. *See In the Matter of a Petition by Minnesota Energy Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-011/GR-13-617, Findings of Fact, Conclusions, and Order at 59 (October 28, 2014).

2. The Department

The Department did not recommend adopting either of the Company's pension-expense-mitigation proposals. It argued that these proposals would result in inappropriate incentives for the Company. The Department recommended that the Commission continue the mitigation measure adopted in the Company's 2012 rate case.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the normalization mechanism adopted in the last case be continued. In the Company's 2012 rate case, the Commission adopted the ALJ's recommendation to (1) extend the NSPM Plan amortization period for unrecognized pension costs from 10 to 20 years and (2) cap the XES pension expense at the 2011 level of $6.1 million and defer the difference in excess of this level to future years.

D. Commission Action

For rate-base purposes, the Commission will require that the pension asset reflect the cumulative difference between actual cash deposits made by the Company reduced by the recognized qualified pension cost determined under the ACM/FAS 87 methods since plan inception, not to exceed the Company's filed request. The Commission will require the Company to provide a detailed compliance filing within ten days of the Commission's decision that explains the calculated amount of qualified pension asset.

The Commission will adopt the ALJ's recommendation to require continuation of the qualified pension mitigation approved in the Company's 2012 rate case. As the ALJ recognized, this mitigation method has previously been found to be consistent with the public and ratepayer interests, and this record supports the same conclusion. The Commission will therefore again require the Company to extend the NSPM Plan amortization period for unrecognized pension costs from 10 to 20 years; and cap the XES pension expense at the 2011 level of $6.1 million and defer any excess of this amount to future years. Deferred amounts will not be included in rate base.

The Commission will further direct that, if approved recovery exceeds future years' pension expense, the Company will apply that amount to recovery of the deferred XES expense amount. The Commission will specify in the ordering paragraphs how that accounting is to be accomplished. The Commission will require the Company to file annual compliance reports that, among other things, provide the pension plans' cost-calculation reports, the XES Plan accumulated deferred balance, and the excess rate level recovery applied toward satisfying the deferral.

Finally, the Commission will direct the company to include information in its next initial rate-case filing addressing several of the issues raised in this case, so that they may be examined more closely. Those issues include details about the Company's target asset allocations, investment strategies, actuarial reports, and other supporting information related to the Company's calculation of its qualified pension expense. A full description of the information required is in the ordering paragraphs.

IX. Retiree Medical Expenses

A. Introduction

Xcel requested recovery of $5,258,504 in costs related to postretirement medical benefits for certain employees who retired prior to 2000. These postretirement medical benefits are paid for retired employees' health care costs such as medical, dental, vision, and life-insurance expenses.

Because the methods of accounting are similar, many issues affecting the calculation of qualified pension expenses similarly affect postretirement medical expenses. Accordingly, just as for pensions, both the discount rate and the 2008 market loss were raised as issues with respect to the retiree medical expenses.[23]

B. Positions of the Parties

1. The Company

Xcel applies FAS 106 accounting methods for retiree medical expenses, which it described as identical to FAS 87 (the method it uses for the XES Pension Plan), with one exception. According to the Company, under FAS 106, asset gains or losses are not phased in but are amortized over the average number of years to retirement for active employees.

The Company applied a discount rate of 4.08%, which it asserted was calculated based on FAS 106 accounting standards, and proposed including the amortized portion of the 2008 market loss in the 2014 test year.

2. The Department

The Department offered arguments that paralleled its arguments about the qualified pension expenses, recommended excluding 50% of the proposed 2008 market-loss amount, and recommended applying a discount rate equal to the weighted average of the expected return on assets.

C. The Recommendation of the Administrative Law Judge

The ALJ found that the proposed inclusion of the 2008 market loss is reasonable and consistent with the Company's long-standing practice of including both market gains and losses in its calculation of this expense. She concluded that including the entire 2008 market-loss amount was appropriate.

The ALJ also found that it is not appropriate to increase the FAS 106 discount rate to match the expected return on assets. However, absent evidence of the prior years' discount rates to calculate a five-year average (as recommended for the pension expense), the ALJ recommended applying an updated FAS 106 discount rate of 4.82%.

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[23] These issues are discussed in greater detail in this order in the sections titled Qualified Pension Discount Rate and Qualified Pension Market Loss

D. Commission Action

There is no basis in this case to reach different conclusions on the similar issues raised with respect to both pension expenses and retiree medical expenses. As the Commission concluded was appropriate for pension expenses, the requested 2008 market-loss amortized amount may be included in the calculated retiree medical benefit cost. And it is appropriate to set the discount rate used to calculate retiree medical benefit costs for ratemaking purposes at the five-year average of the FAS 106-based discount rates.

The historical FAS 106 discount rates were not entered into the record in this proceeding, but the Commission recognizes the FAS 106 discount rates disclosed by the Company in its annual 10-K reports to the Securities and Exchange Commission. The five-year average of the amounts reported by the Company between 2010 and 2014 is 5.08%. Therefore the Commission will require the discount rate for retiree medical expenses to be set to 5.08%.

The Commission will also require that the Company levelize the retiree medical-expense amount by calculating the average of the annual projected benefit cost over two years (the expected length of time before the Company’s next rate case). This will more evenly distribute the rate effect of this expense. Each year’s projected cost amount subject to averaging must be calculated using the Commission-approved assumptions and the most proximate measurement date applicable to each year.

In its next rate case, the Company will be required to provide additional details on its postretirement benefits, including actuarial projections and assumptions, so that they can be more closely scrutinized.

X. Total Labor Costs

A. Introduction

The Company’s 2014 projected test year included $419 million in total labor costs. This figure was 3.9% below actual 2013 labor costs, but it still represented a substantial increase over historical cost levels. (In 2013, labor costs jumped 12.2% because of two unexpectedly long nuclear-plant outages and higher-than-average storm activity.)

The Department claimed that the $419 million figure was inflated and recommended disallowing rate recovery of $5.6 million in total test-year labor expense.

B. Positions of the Parties

1. The Department

The Department argued on the basis of expert testimony that, under normal circumstances, the range of reasonable labor-cost increases was 2% to 3% per year. The agency emphasized that the Company’s 2013 labor costs were abnormally high and should not be used as a baseline. The Department recommended using 2012 costs as a baseline, adding 3% per year thereafter, and disallowing the $5.6 million in test-year costs exceeding the resulting total.

The Department pointed out that labor costs did in fact rise by 3% between 2011 and 2012, confirming, in its view, that the 2011–2012 period was a representative baseline.

2. The Company

Xcel agreed that 2013 labor costs were not representative of costs going forward, noting that its test-year costs were 3.9% below that figure. But the Company argued that labor costs necessarily fluctuate with business and operational conditions and do not necessarily conform to expectations of set percentage increases.

The Company argued that its test-year labor costs were reasonable and pointed out that all increases above 2012 cost levels were due to increased staffing in two departments—nuclear operations and business systems. The Company pointed to its undisputed testimony outlining the need for higher staffing levels in these departments. And the Company noted that, while this increased staffing represented an ongoing increase in labor costs, it did not signify the continuing escalation of labor costs—Xcel projected annual cost increases of only 2–3% for 2014 through 2018.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended permitting rate recovery of all proposed 2014 test-year labor costs.

She pointed out that all increases over 2012 labor costs were attributable to increased staffing in the Company's nuclear and business-systems units and that the Company had provided detailed testimony from core employees explaining the need for increased staffing in these areas. She found that the 3% cap the Department recommended for annual labor-cost increases did not take into account the facts driving the 2014 test-year expense.

D. Commission Action

The Commission concurs with the Administrative Law Judge and will permit rate recovery of the Company's proposed 2014 test-year labor costs.

All test-year increases above 2012 cost levels—the most recent non-aberrant cost data available—are due to staffing increases in Xcel's nuclear-operations and business-systems units. The Company provided detailed testimony explaining the need for higher staffing levels in these units. In the nuclear-operations unit, Xcel needed more staff to meet regulatory and safety requirements and to ensure ongoing in-house expertise; in the business-systems unit, the Company needed more staff to support new cyber-security initiatives and to address issues stemming from aging infrastructure.[24]

No one challenged this testimony, and no one disputed the accuracy, prudence, or reasonableness of the costs it delineated. The Company has demonstrated the reasonableness of its 2014 test-year labor costs and the Commission will permit their recovery in rates.

[24] Ex. 51 (O'Connor Direct) at 83–86; Ex. 62 (Harkness Direct) at 60–62.

XI. Depreciation and Plant Retirements in the 2015 Step — Passage of Time

A. Introduction

Because this is the Commission's first chance to consider a multiyear rate-case proposal, novel issues unique to multiyear rate-setting are presented for the Commission's consideration. One of these issues is how the Company should account for changes in rate base, depreciation expense, and accumulated depreciation reserve over the course of a multiyear plan.

The Department and the Company did not agree on how the Company's rate base should be adjusted from the 2014 test year to the 2015 Step. In a traditional rate case, the Commission would approve a test-year rate base that would remain in effect until the next rate case. All other things being equal, a lower rate base value would mean lower rates. At issue is whether the Company's proposal improperly excluded rate-base reductions attributable to depreciation and expected retirements.

B. Positions of the Parties

1. The Department

The Department recommended that the Commission make two downward adjustments to the Company's proposed 2015-Step rate base: a $17,528,919 reduction for accumulated-depreciation-reserve changes not accounted for by the Company, and a $535,552 reduction to reflect asset retirements planned in 2015. The Department contended that not applying a reduction for known and measurable changes in depreciation reserve would result in unreasonable rates.

The Department limited its exceptions to the ALJ's Report to the ALJ's conclusion (and related findings) that depreciation adjustments for the passage of time would not reduce the Company's 2015 revenue requirement. The Department argued that Xcel had not properly supported the figures that the ALJ used to reach her conclusion. In particular, the Department objected to the ALJ's reliance on an exhibit prepared by Xcel and submitted with the rebuttal testimony of one of its expert witnesses.

2. The Company

Xcel disagreed with the Department's recommended reductions. The Company argued that no passage-of-time reductions were appropriate because the Company's proposal focused on 36 capital projects and associated expenses and not the Company's entire revenue deficiency in the 2015 Step. Xcel objected to what it perceived as asymmetry in the Department's proposal. According to the Company, the Department's recommendation reflects asset values and expenses that decrease from 2014 to 2015, without recognizing expenses that increase over that period.

Xcel argued that even if a passage-of-time adjustment was appropriate, the Department's proposed reduction omitted a depreciation-expense increase that should be included in any passage-of-time calculation. According to the Company's rebuttal testimony, a symmetrically-calculated passage-of-time adjustment would result in a small increase to its rate base, rather than a decrease.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that no downward adjustment to the Company's 2015-Step revenue requirement for the passage of time was necessary. She found that the Department's proposed passage-of-time adjustments did not fully, symmetrically account for capital-related effects of the passage of time. The ALJ found that Xcel had satisfactorily established that no decrease was appropriate because, correctly calculated, a depreciation passage-of-time adjustment would slightly increase Xcel's 2015 rate base.

D. Commission Action

The Commission agrees with and adopts the ALJ's findings and conclusions concerning the Department's proposed $17,528,919 reduction for depreciation expense and accumulated depreciation due to the passage of time. The Commission concludes that Xcel's rebuttal testimony and exhibits adequately support the ALJ's conclusion that no downward adjustment is appropriate in this proceeding.

This is not to say that depreciation adjustments for the passage of time in future multiyear rate plans will never be appropriate, only that there is an adequate basis to conclude that no such reduction is appropriate here.

But the Commission agrees with the Department that a downward adjustment of $535,552 is required to reflect 2015 capital retirements of transmission and distribution facilities. As the Department testified, there is a 2015 impact for these retirements, and it is appropriate to incorporate the impact in the calculation of the Company's 2015-Step revenue requirement.

XII. Delays in In-Service Dates for Capital Projects Included in 2015 Step

A. Introduction

Xcel's initially proposed revenue requirements include costs associated with 733 capital projects for the 2014 test year and costs associated with 116 projects in the 2015 Step. But in an update during the course of this proceeding, the Company acknowledged that 49 of the projects scheduled for 2014 would not be in service until 2015, and that two projects scheduled for 2015 would not be in service until after 2015.

At issue is whether an adjustment to the Company's revenue requirement is appropriate in light of the updated information, and whether the Company's revenue requirement should be calculated using substitute projects identified by the Company.

B. Positions of the Parties

1. The Company

Xcel argued that its proposed 2014 and 2015 revenue requirements are representative of its actual costs. It asserted that, while projects may shift to earlier or later completion as an ordinary matter of implementing projects of this nature, rate-setting involves determining a revenue requirement based on information available at a particular point in time. The Company argued that when in-service dates change, it maintains the flexibility to fund like-kind projects, or projects that are unexpected but necessary.

Opposing the Department's recommendation to reduce its proposed 2014 and 2015 revenue requirements, the Company asserted that it should be allowed to substitute projects in 2014, and argued that because the Company had agreed to a refund mechanism for postponed or canceled 2015 projects, no adjustment is necessary.

2. The Department

The Department opposed allowing Xcel to recover costs of capital projects that have been determined not to fall within the relevant test (or step) year, and asserted that to allow recovery would "constitute a significant and unwarranted departure from traditional ratemaking." It argued that the most up-to-date anticipated in-service dates should be used to calculate the Company's revenue requirements. The Department recommended adjusting the Company's revenue requirement downward based on the updated information, excluding recovery for identified capital projects that will not be in service in the relevant year.

The Department also opposed allowing the Company to substitute projects that had not been vetted by the parties. It disagreed with the ALJ's conclusion that it had had adequate time to review the substitute projects proposed by the Company.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge agreed with the Department's assertion that Xcel's revenue requirements should be based on the most up-to-date in-service information available. The ALJ also concluded that Xcel should only be permitted to substitute replacement projects

> when (1) the Company has shown that the replacement projects are necessary, the costs are prudent, and the projects will be in-service during the test year; and (2) the other parties have had sufficient time to review the proposed replacement projects.[25]

Having found that the Department had sufficient time to review a list of substitute projects proposed by the Company, she concluded that the Company's revenue requirement should be determined with those projects as substitutes.

The ALJ therefore recommended that the Commission reduce the Company's proposed 2014 and 2015 revenue requirements to reflect updated in-service dates for projects, and allow substitution of projects identified by the Company. The ALJ's recommendation would reduce the Company's 2014 revenue requirement by $1.8 million.

D. Commission Action

The Commission will adopt the ALJ's findings and conclusions, and require that the 2014 and 2015 revenue requirements be calculated with updated in-service-date information, but allow inclusion of replacement projects specified by the Company in Ms. Perkett's Rebuttal Testimony, Schedule 11.

[25] ALJ's Report ¶ 499.

The Commission recognizes that changes to in-service dates often arise in the course of managing capital projects like those identified by the Company. If the Commission is to consider updated in-service-date information provided during the course of the rate case, it is reasonable also to consider the Company's list of projects that are candidates to substitute for delayed or canceled projects as well. The Commission agrees with the ALJ that this outcome is a reasonable balance of the interests expressed by the Department's and the Company's positions that will result in just and reasonable rates.

XIII. Nuclear-Refueling-Outage Costs — 2015 Step

A. Introduction

Xcel seeks to include $89.3 million in amortized nuclear-refueling-outage costs in the 2014 test year. According to the Company, this amount does not include capital costs or regular O&M expenses, which are accounted for elsewhere. Because these costs can vary significantly, the Company defers and amortizes them. At issue is whether a change in the amortized cost should be reflected in the Company's 2015-Step revenue requirement.

B. Positions of the Parties

Xcel's information reflected a $5.5 million decrease from 2014 to 2015 in the amortized expense that was not reflected as a downward adjustment in its proposed 2015 Step. The OAG and the Department (initially) recommended that the 2015-Step revenue requirement be reduced by $5.5 million to reflect the lower 2015 amortized expense.

The Company responded that the nuclear-refueling-outage costs are neither capital costs nor non-capital costs associated with a step-year capital project. It argued that the adjustment proposed by the Department and the OAG was inconsistent with the Commission's Multiyear Rate Plan Order, which indicated that step-year adjustments were limited to costs related to specific, clearly identified capital projects, and related non-capital costs. According to the Company, there are corresponding step-year cost increases that should also be considered if the 2015 revenue requirement is to be adjusted for non-capital cost variations such as this.

The Department withdrew its recommendation upon the Company's explanation that nuclear-refueling-outage costs are not capital costs. The OAG, however, still argued for the adjustment in 2015. The OAG argued that these costs are similar to capital costs and so should be treated like capital costs.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that the Commission's Multiyear Rate Plan Order precluded adjusting the 2015-Step revenue requirement for the change in the amortized nuclear-refueling-outage costs. The ALJ further concluded that if an adjustment were made for these costs, only through symmetrical consideration of other similar upward and downward variations could the Commission establish just and reasonable rates. Accordingly, the ALJ recommended not making the adjustment recommended by the OAG.

D. Commission Action

The Commission agrees with Xcel, the Department, and the ALJ. No adjustment is required in the 2015 Step for the $5.5 million reduction in nuclear-refueling-outage cost in 2015.

Consideration of the full spectrum of increasing and decreasing non-capital costs in a step year would undermine the efficiency purpose of multiyear rate-setting—to do so would effectively require a full rate case for each year of the plan. The Commission concludes that the amortized nuclear-refueling-outage costs are among the costs for which step-year adjustments should only be accomplished in conjunction with a fuller consideration of all rising and falling non-capital costs. Neither the deferral-and-amortization method of accounting for these costs—nor the Commission-approved carrying charge—transform them into capital costs for the purpose of implementing a multiyear rate plan.

XIV. Nuclear-Refueling-Outage Costs — Carrying Charge

A. Introduction

Since the conclusion of its 2008 rate case, Xcel has been deferring and amortizing its nuclear-refueling-outage costs. The Commission approved this cost treatment to ensure greater accuracy in cost recovery by reasonably matching the time these costs are incurred with the time they are recovered while avoiding substantial fluctuations in these costs between rate cases. The Commission has in the past approved a carrying charge to compensate the Company for the time value of money forgone as part of this deferred recovery.

B. Positions of the Parties

1. The Company

Xcel proposed that it be permitted to impose a carrying charge equal to its overall rate of return, as has been approved in prior rate cases. The Company argued that a carrying charge is appropriate where, as here, the Company uses operating funds to cover costs before receiving those funds from customers.

2. The OAG

The OAG opposed allowing the Company to earn a carrying charge for the deferred nuclear-refueling-outage expenses. It argued that authorizing a carrying charge on these expenses deprives the Company of incentive to keep its refueling costs low.

C. The Recommendation of the Administrative Law Judge

The ALJ, after reviewing previous Commission decisions authorizing a carrying charge for these expenses, found no reason to reach a different conclusion and recommended that a carrying charge again be permitted.

D. Commission Action

As the ALJ recognized, the Commission has in Xcel's last two rate cases authorized a carrying charge for the amortized nuclear-refueling-outage expenses. The Commission again concludes that a carrying charge at the Company's overall rate of return is reasonable.

The underlying reasoning is unchanged: the Company's approved rate of return is the appropriate time cost of money for this expense, which is generally amortized over 18–24 months—longer than the Company's time frame for short-term debt. And the Company credits ratepayers at the rate of return when amortized amounts exceed actual costs, ensuring equitable treatment. The requirement that the Company demonstrate that its nuclear-refueling-outage costs are reasonable and accurate is also unchanged.

The Commission will therefore allow Xcel to include the unamortized nuclear-refueling-outage costs in rate base and earn the overall allowed rate of return on that balance.

XV. Costs of Cancelled Prairie Island Extended Power Uprate Project

A. Introduction

The Company seeks rate recovery of $78.9 million in costs incurred for a cancelled project to increase the generating capacity of its Prairie Island nuclear plant. The $78.9 million figure includes $66.1 million in total expenditures and $12.8 million in accrued AFUDC (Allowance for Funds Used During Construction), the net cost of money used for construction.

On December 18, 2009, the Commission issued a certificate of need for the project, called an "extended power uprate." The Commission found that there was a need for the additional 164 MW of electricity the project would generate and that the extended power uprate the Company proposed was the most reasonable means developed in the record for meeting that need.[26] The project was one of more than 100 similar projects proposed throughout the country at that time; the order stated that as of the date of issue the federal Nuclear Regulatory Commission (NRC) had completed its review of some 118 power-uprate projects.[27]

As the project progressed, problems developed. In January 2011, the Company determined, in conjunction with Westinghouse, the manufacturer of the Prairie Island nuclear reactors and the firm conducting the engineering analyses for the project, that an uprate of 164 MW could not be achieved cost-effectively; the Company lowered its uprate goal to 132 MW.[28]

In March 2011, there was a disaster at the Fukushima Daiichi nuclear power plant in Japan. This disaster prompted changes to the NRC review process, which became lengthier, more detailed, increasingly backlogged, and more expensive. In August 2011, the Company had a meeting with NRC staff that led it to conclude that heightened review requirements would substantially

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[26] *In the Matter of the Application of Northern States Power Company for a Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, Docket No. E-002/CN-08-509, Order Accepting Environmental Impact Statement and Granting Certificates of Need and Site Permit with Conditions (December 18, 2009).

[27] *Id*. at 8.

[28] ALJ's Report ¶ 438.

increase the cost of preparing its application for an NRC license and would delay project implementation by about two years.

At about the same time, a nationwide pattern of significant cost overruns for uprate projects similar to the one planned for Prairie Island emerged. Meanwhile, Company sales forecasts indicated a persistent softening of demand for electricity within its service area. And the price of natural-gas generation, a potential competitor of increased Prairie Island generation, continued to decline, due to structural changes in the natural-gas sector.

On October 7, 2011, the Company filed a letter in its pending resource-plan case apprising the Commission that it saw a need for a comprehensive update of its 2011–2025 resource plan in light of obstacles to completing the Prairie Island extended power uprate on schedule. On December 1, 2011, it filed the update, stating, among other things, that the extended power uprate might no longer be in the public interest and that it planned to file a Notice of Changed Circumstances in the certificate-of-need docket requesting Commission review of that issue.

Meanwhile, the Company reduced spending on the uprate in the third quarter of 2011 and ended all spending by the end of that year, with the exception of the Westinghouse contract, whose early-termination penalty provisions would have been nearly equal to the cost of performance.

On April 2, 2012, the Company filed the Notice of Changed Circumstances in the certificate-of-need docket. The Commission initiated an all-stakeholder comment-and-review process. On February 27, 2013, the Commission issued an order terminating the certificate of need prospectively, explicitly deferring the issue of cost recovery for later treatment. Cost recovery issues will be addressed below.

B. Positions of the Parties

1. The Company, the Department, and the Chamber of Commerce

These three parties initially took different positions from one another. They agreed that the costs had been prudently incurred and should be recovered but disagreed on amortization periods and on whether the Company should earn any return on unamortized costs.

The Company initially proposed recovery over 12 years while earning its full rate of return on unamortized balances or, in the alternative, recovery over six years with no return. The Department initially recommended recovery over 20.3 years, the remaining life of the plant, with no return. The Minnesota Chamber of Commerce initially recommended recovery over 20 years with no return.

During evidentiary hearings these three parties agreed that the public interest supported recovery over 20.3 years with a return at the Company's cost of debt, 2.24%, and recommended that ratemaking treatment.

2. The OAG

The OAG argued that, at a minimum, the Commission should reject rate recovery of the following:

1) A $10.1 million pre-tax charge on uprate-related expenses the Company recorded at the end of 2012, on grounds that costs that have been written off are no longer recoverable.

2) $9.2 million in AFUDC costs incurred after the Company's August 2011 meeting with NRC staff, which, the OAG contended, should have apprised the Company that the project was no longer viable. At that point, the OAG argued, AFUDC was no longer appropriate under Federal Energy Regulatory Commission (FERC) accounting rules limiting AFUDC accruals to projects that are "viable and ongoing."

3) Payments made to Westinghouse, the project's engineering consultant, after the August 2011 meeting with the NRC staff. Although the contract with Westinghouse subjected the Company to termination payments nearly equal to the payments made after August 2011, the OAG claimed that the Company had been imprudent in agreeing to those terms, and that the costs were therefore unrecoverable.

4) Any return on any extended uprate costs for which rate recovery might be permitted.

3. The ICI Group

The ICI Group recommended denying recovery of all costs associated with the cancelled project, on grounds that the project did not meet the traditional cost-recovery standard of being used and useful. The Group also contended that permitting recovery of the costs of cancelled projects would encourage utilities to incur costs for marginal or imprudent projects.

The Group opposed any return on unamortized costs for which rate recovery might be permitted, or, in the alternative, recommended a very low return—perhaps the rate paid on U.S. Treasury bills or bonds—to reflect the nearly risk-free nature of the investment.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended adopting the course of action recommended by the Department, the Company, and the Chamber of Commerce—permitting cost recovery over 20.3 years, the remaining life of the plant, with a return on unamortized balances at the Company's cost of debt, 2.24%.

The ALJ found that the Company had acted prudently and in good faith both in developing the project and in cancelling it. She rejected the ICI Group's claim that the project's failure to attain "used and useful" status precluded rate recovery, noting that the Commission has permitted recovery of the costs of cancelled projects in the past, based on the unique circumstances and specific facts of each case.

She rejected the OAG's claims that the $10.1 million in costs represented by the 2012 pre-tax charge and the AFUDC accrued after the 2011 meeting with NRC staff were unrecoverable, finding that accounting rules—which required the first action and allegedly barred financial reporting of the second—did not dictate ratemaking treatment. She rejected the OAG and ICI Group claims that the Company's execution of the Westinghouse contract, with its substantial early-termination penalties, had been imprudent, finding that those claims were based solely on hindsight and speculation.

The ALJ rejected the OAG's claim that costs and AFUDC incurred after the Company's August 2011 meeting with NRC staff should be disallowed as imprudent, noting that both the Company and the Department conducted independent cost-benefit analyses in 2012 that found the project still viable.

She rejected the ICI Group's claim that permitting recovery of the costs of cancelled projects would encourage utility spending on marginal or imprudent projects, noting that the Commission had reached the opposite conclusion in at least two recent cases.[29]

The ALJ found that a 20.3-year recovery period with a return at the 2.24% cost of debt was a reasonable outcome for both ratepayers and shareholders. She found the 20.3-year recovery period reasonable because it was the remaining life of the plant—the same time period during which the completed project would have served ratepayers and had its costs recovered in rates. And she found a return on unamortized costs at the Company's cost of debt reasonable, given the long recovery period and the time value of money.

D. Commission Action

The Commission concurs in the Administrative Law Judge's findings, conclusions, and recommendations, and will permit recovery of the cancelled project's costs over 20.3 years, with a return on unamortized balances at the Company's 2.24% cost of debt.

The Commission concurs with the ALJ that the record demonstrates that Xcel acted prudently and in good faith both in developing the project and in cancelling it. The Company did not embark on the project hastily or unilaterally—the need for and reasonableness of the project were scrutinized by stakeholders and regulators during an exhaustive certificate-of-need proceeding, which resulted in the Commission issuing a certificate of need.

Nor did the Company fail to recognize, react to, and disclose signs of trouble as they developed. Less than two months after the NRC meeting clarifying the new licensure standards and processes, the Company filed a notice of its intent to update its resource plan in light of these and other new realities. Less than two months later, it filed the update, which laid out the challenges the project faced and attempted to compare its costs and benefits with those of alternative resources.

Four months later, it filed a request for Commission review of the continued reasonableness of the project, given the changed circumstances. That request led to an expedited—but necessarily time-consuming—proceeding, which resulted in prospective termination of the certificate of need. These actions, and the time frames in which they were taken, demonstrate a diligent and responsible approach to securing regulatory review of the difficult technical and policy issues posed by the possible need to cancel the project.

[29] *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-001/GR-10-276, Findings of Fact, Conclusions, and Order (August 12, 2011); *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Findings of Fact, Conclusions, and Order (April 25, 2011).

The Commission concurs with the ALJ that the 2012 pre-tax charge taken by the Company to comply with financial-reporting requirements and the post-NRC-meeting AFUDC accruals the OAG claims are barred by FERC accounting rules are rate-recoverable. Accounting rules can provide valuable information about the nature of costs, but they do not dictate their ratemaking treatment.

Nor does the Commission concur with the OAG and the ICI Group that the costs of the Westinghouse contract were imprudently incurred and should be disallowed. As the ALJ found, these claims appear to be based entirely on hindsight and speculation, whereas the Company provided detailed testimony about its selection of Westinghouse as its engineering consultant. Among other considerations, as the manufacturer of the Prairie Island reactors and the designer of the Prairie Island plant, Westinghouse had unique knowledge of the facility and control of proprietary information necessary to complete the project.[30]

The Commission does not concur with the ICI Group that permitting recovery of cancelled-project costs encourages utilities to invest in marginal or imprudent facilities. While cancelled-project costs require careful scrutiny, the Commission continues to believe that a blanket prohibition on their recovery could be inequitable to utilities acting in good faith to meet their responsibilities to ratepayers and could encourage utilities to complete projects rendered marginal or imprudent by changing circumstances. As the Commission explained in the Interstate Power rate case in 2011:

> The Commission concludes that there is no public interest or regulatory benefit to be gained by disallowing costs prudently incurred in good faith to meet future need. And there is much to be lost by potentially chilling a utility's diligence in developing resources and in promptly withdrawing from projects when experience shows that they will no longer serve ratepayers' best interests.[31]

For all these reasons, the Commission will permit rate recovery of these cancelled-project costs under the terms set forth above.

XVI. Recovering Pleasant Valley and Border Winds Project Costs

A. Introduction

The Company proposed to include in the 2015-Step base rates the capital costs for two new wind farms it expects to place into service by the end of 2015, Pleasant Valley and Border Winds.

New capital projects go into rate base at the average of their first-of-year and end-of-year project balances. If these projects go into service late in the year, as expected, base-rate recovery would for a time exceed the dollar-for-dollar recovery the Company would receive if it recovered project costs through the Renewable Energy Standard (RES) rider, an automatic-rate-adjustment

[30] Ex. 49 (McCall Direct) at 12, 16–17.

[31] Docket No. E-001/GR-10-276, Findings of Fact, Conclusions, and Order at 33 (August 12, 2011).

mechanism used to ensure recovery between rate cases of costs incurred to comply with the Minnesota Renewable Energy Standard.[32]

The Company did, however, propose to use the RES rider to true up discrepancies between the amount of federal production tax credits (PTCs) it projected receiving from the wind farms over the course of the year and the amount of PTCs it actually received.

B. Positions of the Parties

The Minnesota Chamber of Commerce recommended recovering the costs of these projects through the RES rider, both because rider recovery would ensure that ratepayers did not begin to pay for the projects until they were actually in service and because rider recovery would reduce the 2015-Step revenue requirement by some $5.538 million. The Chamber pointed out that the Commission has sometimes permitted costs to remain in riders despite an intervening rate case, and that some project costs—the PTCs—would continue to be trued up through the rider in any case.

The Company stated that it placed the wind farms in the 2015-Step rate base instead of the RES rider mainly because, in its Multiyear Rate Plan Order, the Commission directed filing utilities to scrutinize and streamline rider recovery as much as possible.[33] The Company stated that it did not have a strong preference for either rate-recovery method. It did not, however, view project delay as a major risk, since all parties to the construction contracts understood that achieving operational status by the end of 2015 was critical to receiving the favorable tax treatment on which the projects' economic projections were based.

The Department stated that it considered base-rate recovery superior to rider recovery as a matter of regulatory practice and consistency with the generic order, but did not oppose rider recovery. It, too, did not consider project delay a major risk.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that both rate-recovery methods were reasonable and that the Commission should decide which method was more appropriate, based in part on the relative value it placed on reducing rider use and moderating the rate impact of the 2015 Step.

D. Commission Action

The Commission will require rate recovery through base rates with a PTC true-up through the RES rider.

While the Chamber is correct that rider recovery would provide some protection against the recovery of costs not incurred because of delays in project completion, the Commission concurs with the Company and the Department that delays are unlikely, given the contracts' emphasis on timely completion and the financial consequences delays would entail. Further, the Company has committed to refund to ratepayers any difference between total capital costs included in the 2015 Step and total capital costs incurred, in large part alleviating this concern.

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[32] Minn. Stat. §§ 216B.1691, subd. 2a, .1645, subd. 2a.

[33] Docket No. E,G-999/M-12-587, Multiyear Rate Plan Order at 7–8, 12, 14.

The main rationale for rider recovery, therefore, would be to moderate the 2015-Step increase. This rationale, however, is not only outcome-driven, but will not necessarily achieve the outcome desired, since the actual costs flowing through the RES rider could exceed the projects' 2015 rate-base component, depending on factors such as the dates the projects actually go into service, the timing of the next rate case, and the magnitude of costs that would be posted to the rider in the intervening period.

Further, as the Commission made clear in the Multiyear Rate Plan Order, the Commission sees value in seizing the opportunity to examine, rationalize, and simplify existing riders when utilities file multiyear rate plans. Riders exist to address regulatory lag, as do multiyear rate plans, but both ratemaking devices introduce additional complexity to the ratemaking process that can present ratepayer risks.

The statute acknowledges this by permitting the recovery of costs expected to occur in future years "provided that the costs are not being recovered elsewhere in rates."[34] For the same reason, the Multiyear Rate Plan Order requires detailed disclosure and analysis of existing riders when utilities file multiyear rate plans:

> 10. Where a utility is recovering continuing, predictable costs through riders, a utility seeking approval of its multiyear rate plan shall propose to recover those costs via base rates at the beginning of the rate case.
>
> 11. Regarding other riders and cost recovery mechanism, the utility shall design its multiyear rate plan to consolidate as many of them as practical, in the most reasonable manner available. . . .
>
> 22. Regarding an applicant's existing rate riders, an application for a multiyear rate plan must include or be accompanied by the following:
>
> A. A proposal to restructure its riders as follows:
>
> 1) a proposal to recover through base rates the cost of existing riders that are likely to continue and are sufficiently predictable to support recovery through base rates,
>
> 2) a proposal to consolidate as many other riders and cost recovery mechanisms as is practical, and
>
> 3) a demonstration that the utility's proposals to restructure its rate riders are the most reasonable alternatives available to the utility.

[34] Minn. Stat. § 216B.16, subd. 19 (b).

> B. Clear evidence that double recovery will not occur as a result of the way the utility proposes to handle its multiyear rate plan and existing riders, including evidence that the periods during which the utility is recovering a cost via a rider does not overlap with the period during which it is recovering the cost via base rates or the multiyear rate plan mechanism.[35]

The Commission continues to view reduced dependence on rate riders and their continuing simplification as important regulatory goals and will not authorize rate recovery of the capital costs of these wind facilities through the RES rider.

As a housekeeping matter the Commission will direct the Company to include estimated PTCs in rate base, as agreed by all parties, for ultimate true-up in the RES rider. The Commission will also require the Company to report to the Commission and potentially pass through to ratepayers any contract cost reductions or performance penalties or other cost changes that develop in the course of contract completion.

Finally, the Commission will direct the Company to report in its next RES-rider filing on the results of its ongoing discussions with the Chamber and other stakeholders on alternative cost-recovery formulas designed to allocate risks and create cost-savings incentives for these and other wind resource acquisitions undertaken by the Company. These discussions were required as part of Commission action in the Company's last wind-acquisition docket,[36] and the parties report they are continuing.

XVII. Nuclear-Depreciation-Reserve Surplus

A. Introduction

The Xcel Large Industrials (XLI) contended that there was a $208 million surplus in Xcel's nuclear-production-plant depreciation reserve; the surplus consisted of the difference between the Company's theoretical reserve—what it would have collected in depreciation if all facts currently known had been known when depreciation rates were first set—and its actual reserve—amounts actually collected. This difference existed mainly because the operating licenses—and therefore the useful lives—of Xcel's two nuclear plants had been extended beyond their original licensure periods.

XLI proposed amortizing this surplus over five years, reducing annual revenue requirements by some $41.6 million per year.

The Company stated that its calculations showed a $72.5 million difference between its actual and theoretical nuclear depreciation reserves. But it cautioned that depreciation surpluses are just estimates, not guarantees, and that the amount of the actual reserve might ultimately be required

[35] Multiyear Rate Plan Order at 13–14.

[36] *In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of 600 MW of Wind Generation*, Docket No. E-002/M-13-603, Order Approving Acquisitions with Conditions at 15 (December 13, 2013).

to meet contingencies such as changes in service lives or retirement costs. The Company recommended permitting any surplus to self-correct over the lives of the nuclear plants.

The Department and the OAG also opposed amortization, arguing that its rate benefits would be short-term and its adverse rate consequences long-term.

XLI had raised this issue in the Company's last rate case as well, where the Commission determined that the preponderance of the evidence did not demonstrate that a surplus existed; the Commission did, however, direct the Company to address the issue in more detail in its next rate case.[37]

B. Positions of the Parties

1. XLI

XLI maintained that its $208 million figure was correct and that Xcel's $72.5 million figure was flawed by failing to use "vintage" accounting—giving each asset its potential useful life regardless of the life of the plant in which it is situated—and by including future interim capital additions. Vintage accounting was reasonable, they contended, because it was plausible that the Company would again extend the operating licenses, and therefore the service lives, of its nuclear plants.

XLI emphasized that depreciation is not intended to help cushion the impact of future capital investments but to recover current expenses; it argued that the rate consequences of substantial capital improvements in the foreseeable future should play no role in the decision to amortize or not amortize any existing depreciation surplus. They contended that ratemaking principles of intergenerational equity required returning the surplus to ratepayers as soon as reasonably possible.

They argued that amortizing this depreciation surplus would be consistent with the Commission's decision in the last rate case to amortize the surplus in the Company's transmission, distribution, and general-plant depreciation reserve.[38]

2. The Company

Xcel emphasized the uncertainties surrounding setting depreciation rates for nuclear facilities and that depreciation rates reflected estimates of costs and service lives, not hard facts. The Company argued that there was no realistic comparison between the transmission, distribution, and general-plant depreciation account and this account—the much smaller number of assets in this account and the high cost of retiring nuclear plants made the surplus less certain and the impact of miscalculation more serious.

The Company argued that vintage accounting was inappropriate because the useful lives of nuclear assets are inextricably tied to the lives of the facilities in which they are situated—the useful life of a pump in a nuclear plant with a 15-year remaining life is 15 years, even if the pump could conceivably be used for 40 years if the plant remained in service for that long. The Company stated that it would be unreasonable to assume in setting depreciation rates that the operating licenses and service lives of both its nuclear plants would again be extended.

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[37] Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order at 29 (September 3, 2013).

[38] *Id*. at 25–29.

The Company denied that it factored future capital additions into its depreciation rates.[39] It stated that it noted its recent and continuing substantial investments in nuclear facilities only for purposes of helping parties gauge the consequences that amortizing the surplus would have on total depreciation expense and future rates. It stated that recent large additions to its nuclear facilities would substantially increase depreciation expense and that amortizing the surplus would exacerbate the rate impact of those additions.

3. The Department

The Department emphasized that the $72.5 million surplus currently reflected in the Company's nuclear depreciation account is only an estimate, not a guarantee.

The agency argued that amortizing the surplus in the depreciation reserve would be short-sighted, exchanging a short-term benefit for higher rates over the long term. It stated that it was difficult to conclude, given the Company's recent and ongoing substantial nuclear capital investment, that ratepayers had overpaid nuclear depreciation expense.

4. The OAG

The OAG opposed amortizing the surplus, stating that amortization would lead to ratepayers paying depreciation twice and a higher return on a larger rate base.

The OAG concluded that the short-term benefits of amortization would be outweighed by its long-term burden on ratepayers.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that a nuclear depreciation surplus exists, but that its amount is unclear.

She found that XLI was likely overestimating the surplus by using vintage accounting. She rejected vintage accounting on grounds that the life of a nuclear plant determines the lives of the assets within it and that the reasonable measure of the lives of Xcel's nuclear plants was the length of its operating licenses. She found that it was not reasonable at this point to assume that those operating licenses—and the plants' service lives—would be extended. She also found that Xcel was likely underestimating the surplus by including interim plant additions in initial-depreciation accounts.

She found that the purpose of depreciation is to recover current costs and that to the extent that the current depreciation reserve exceeds straight-line annual allocation of those costs, amortization of the surplus could reasonably be required.

She found that whether the Commission should require amortization of some amount below XLI's estimated surplus, such as the Company's estimate, would depend on the size of the final revenue deficiencies, the need to ensure adequate funding for future plant retirements, and a careful analysis of policy factors such as rate-shock mitigation, rate stability, and

[39] Xcel Initial Brief at 102; Xcel Reply Brief at 82.

intergenerational equity. She found that the Commission might also consider the impact of the Company's rate-moderation proposals, if adopted.

D. Commission Action

The Commission will not require amortization of the apparent surplus in the Company's nuclear-plant depreciation reserve but will permit that surplus to self-correct over the lives of the two nuclear plants.

The nuclear surplus is not reasonably comparable to the transmission, distribution, and general-plant (TDG) surplus that the Commission ordered amortized in the last rate case. The TDG surplus applied to a huge pool of transmission, distribution, and general-plant assets. Given the large number of assets in the pool, miscalculations of individual service lives or individual retirement or salvage costs were unlikely to have a substantial financial impact on the Company and its ratepayers.

This surplus, on the other hand, applies to two nuclear plants and their associated assets. Given the small number of assets in the pool, miscalculations of individual service lives or individual retirement costs or salvage values could have a substantial financial impact on the Company and its ratepayers, especially given the extremely high cost of decommissioning nuclear power plants. Similarly, unforeseen contingencies affecting the timing or cost of plant retirements carry more serious financial consequences for this smaller, less diversified group of assets than for the group of assets in the TDG account.

The Commission concurs with the Administrative Law Judge that XLI's calculation of the surplus is significantly overstated. The Commission also concurs that, while it might be reasonable to amortize whatever significantly smaller surplus might exist, amortization is not required and should only be done if necessary for rate relief, after careful consideration of the need to ensure adequate funding for nuclear-plant retirements and the impact of any other rate-moderation measures ordered in this case.

On the basis of that analysis, the Commission finds that the uncertainties and risks that would accompany reducing the nuclear depreciation reserve exceed the benefits of amortizing whatever surplus might exist. Permitting the surplus to self-correct over the remaining lives of the nuclear plants will help ensure adequate funding for plant retirements and help protect ratepayers from the financial consequences of unforeseen contingencies. And the rate-moderation measures adopted in this case will help smooth the transition to 2014-test-year and 2015-Step rates without compromising these goals.

For all these reasons, the Commission will not adopt XLI's proposal to amortize the difference between the actual and theoretical nuclear depreciation reserves but will permit that difference to self-correct over the remaining lives of the plants.

XVIII. Corporate Aviation

A. Introduction

The Company has proposed to recover $954,000 for corporate-aviation costs in the 2014 test year, which is 50% of what it actually has budgeted to spend in 2014, on a Minnesota-jurisdictional basis. The Commission has, in prior rate cases and in the absence of a record that would support more precision, allowed recovery of 50% of corporate aircraft expenses as a reasonable proxy for value to the utility.

Under Minn. Stat. § 216B.16, subd. 17, the Commission may not allow recovery for travel expenses that the Commission determines are unreasonable and unnecessary for the provision of utility service. The statute requires utilities seeking recovery for such expenses to itemize the expenses as specified by the Commission, and "include the date of the expense, the amount of the expense, the vendor name, and the business purpose of the expense."[40]

In Xcel's last rate case, the Commission required that the Company include in its next initial rate-case filing "more detailed flight data reports" including "the charged employee, each employee passenger and his/her assigned operating company, the other passengers on flight and reason for use, and primary purpose for scheduling the flight."[41] The Commission also determined in Xcel's 2010 rate case that the Company must provide more detailed recordkeeping and reporting for corporate aviation.[42]

B. Positions of the Parties

1. The Company

Xcel asserted that it complied with the Commission's reporting requirements set in the last rate case to the best of its ability. Relying on Commission decisions in previous rate cases, for Xcel and for other utilities, the Company proposed to recover 50% of its corporate-aviation expenses. It argued that it had offered information sufficient to support the 50% allowance, and disagreed with the OAG that any further downward adjustments were appropriate.

2. The OAG

The OAG argued that the corporate-aviation expense, even reduced by 50%, should be further reduced. It suggested that the Company should be limited to recovery of the cost of comparable commercial air travel—$300 per one-way trip.

The OAG also recommended reductions for flights identified that it argued did not benefit ratepayers, including reporting categories "personal travel," "investor relations," and "aviation use." The OAG further argued that other reporting categories were not detailed enough to support recovery. It asserted that the Company's air travel reporting did not comply with the Commission's order in the previous rate case and demonstrated that the Company did not have an adequate system to ensure that corporate flights were for a valid business purpose.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that the Company had substantially complied with the Commission's previous orders requiring additional information from its corporate-aviation recordkeeping. She

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[40] Minn. Stat. § 216B.16, subd. 17(a), (b).

[41] Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order at 53 (September 3, 2013).

[42] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-10-971, Findings of Fact, Conclusions, and Order at 36 (May 14, 2012).

found it reasonable to include 50% of the approximately $1.9 million budgeted for Minnesota-jurisdictional 2014 corporate-aviation costs, or $954,425.

The ALJ did not recommend further reductions such as those proposed by the OAG. The ALJ relied in part on the Commission's previous willingness to approve corporate-aviation expenses with the level of support provided by the Company. She also determined that the recommended 50% reduction of the expense adequately excluded travel expense that did not benefit ratepayers. The ALJ recommended that the Commission consider whether it wanted more detail in the aviation records, and if so, that the Commission specify the level of detail desired.

D. Commission Action

The Commission disagrees with the ALJ's aviation-related recommendations and will instead adopt revised conclusions as set forth below and in the ordering paragraphs.

The Commission concludes that the Company's proposed 50% exclusion to its jurisdictional corporate-aviation costs does not adequately remove flight costs that were incurred for reasons other than for the provision of utility service. The Commission will therefore not adopt ALJ Finding 559. The Commission will require that corporate-aviation costs be further reduced by the cost of flights categorized as personal travel (34 total company flights) and investor relations (45 total company flights). These flights were not required for the provision of utility service and should not be recovered.

The Commission will also disallow recovery for reported expenses with insufficient detail to allow the Commission to make an informed determination about their necessity and reasonableness. Minnesota law requires Xcel to provide information about the "business purpose" of each flight before recovery is permissible. Xcel did not meet this requirement because the "business purpose" descriptions in Xcel's flight log do not provide any information to determine the true business purpose of the flights.

Because Xcel has not demonstrated that the flights coded as Executive Business Travel, Director Travel, Manager Travel, and Business Area Travel have a business purpose necessary for the provision of utility service, they must be disallowed. Accordingly, the Commission will require the Company to reduce corporate-aviation costs further by the cost of each flight with the following descriptions:

- Business Area Travel (1,668 total company flights);
- Director Travel (615 total company flights);
- Manager Travel (55 total company flights);
- Xcel Executive Business Travel (831 total company flights).[43]

Finally, the Commission will require that the Company provide, in future rate cases seeking recovery of corporate aviation, more detailed, accurate records of the actual business purpose for flights that are scheduled, rather than reducing all flights to a generic "code." This will permit the

[43] The OAG also sought to exclude recovery for flights categorized as "Shareholders Meeting," but the Commission will allow recovery for those flights because annual shareholder meetings are required by statute, and the travel occurred close in time to the Company's annual meeting.

Commission to evaluate the reasonableness and necessity of the expenses for the provision of utility service, as required by statute.

XIX. Proposed FERC Comparison Study KPI Benchmarks

A. Introduction

Xcel annually conducts a study comparing its cost structure to peer companies. According to the Company, the study assesses performance in the following expense categories: nonfuel operation and maintenance (O&M), administrative and general, customer care, distribution, transmission O&M, and production O&M. In the 2013 study, the Company's performance was among the bottom half of its peers in two categories: nonfuel O&M and transmission O&M. Parties questioned whether the Company should implement benchmarks to improve performance in those categories.

B. Positions of the Parties

The Department and the Chamber recommended that the Commission require the Company to add nonfuel O&M and transmission O&M benchmarks as additional Key Performance Indicators (KPIs). KPIs are used as part of the Company's annual incentive program to measure and reward performance toward business goals.

Xcel opposed adding these additional benchmarks, arguing that their addition was unnecessary. It argued that it already has implemented a nonfuel O&M growth KPI. The Company also contended that using the transmission O&M benchmark from its 2013 study would result in inapt comparisons. But the Company has offered to work with the Chamber to develop a reasonable KPI metric for transmission costs.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that an additional KPI for transmission O&M was warranted, but concluded that because the Company already implements a nonfuel O&M growth KPI, adding a KPI for nonfuel O&M was not necessary.

D. Commission Action

The Commission agrees with the ALJ that the concerns about transmission O&M costs raised by the Chamber and agreed to by the Department justify closer examination. To ensure that an appropriate benchmark can be established, careful attention to the selection of peer companies will be necessary. The Commission will therefore require the Company, in its next rate case, to (1) present a new KPI for transmission O&M costs, and (2) provide a comparison study of its transmission O&M costs by using appropriate peer companies, along with justification for why certain utilities were included or excluded.

At this time, the Commission will not make a determination as to whether the Company's KPI target to restrict increases in its recoverable nonfuel O&M costs sufficiently addresses concerns raised by the parties. But the Commission agrees with and adopts the ALJ's determination that no additional nonfuel O&M KPI benchmark is necessary at this time.

XX. CWIP and AFUDC

A. Introduction

Construction Work in Progress (CWIP) and Allowance for Funds Used During Construction (AFUDC) are accounting devices used to permit utilities to recover the financing costs of capital projects while they are under construction. Capital costs incurred during construction are placed in rate base as CWIP; the associated financing costs are added to net operating income as AFUDC, normally offsetting any return on CWIP until the plant under construction goes into service. At that time, CWIP and AFUDC are recovered over the life of the asset through the recording of book depreciation expense.

The Commission has been following this approach in Xcel rate cases since 1977. The Commission is authorized to consider CWIP and AFUDC in ratemaking under Minn. Stat. § 216B.16, subds. 6 and 6a.

In the Company's last rate case, some parties claimed that the Company was misusing CWIP/AFUDC by including short-term and low-cost projects. They also claimed that CWIP was inappropriate in principle because it shifted shareholders' risks to ratepayers and forced ratepayers to bear costs for which they receive no current benefit.

The Commission permitted the inclusion of CWIP and AFUDC in that case, but required that the Company provide a more detailed explanation of its CWIP and AFUDC practices in its next rate case:

> In the initial filing in its next rate case, Xcel shall provide evidence of FERC's accounting requirements for CWIP/AFUDC and demonstrate that it has met the FERC requirements. It shall also address whether a minimum dollar level should be set for projects placed in CWIP.[44]

The Company included detailed testimony on its CWIP and AFUDC practices in its initial filing in this case. No party disputed that the Company had demonstrated its compliance with FERC accounting requirements.

The OAG and the Commercial Group challenged the reasonableness of CWIP and AFUDC in principle, however. And the OAG also recommended that if the use of CWIP and AFUDC continued to be permitted, the AFUDC rate should be lowered and the application of CWIP and AFUDC should be limited to projects whose costs exceeded $25 million.

B. Positions of the Parties

The Commercial Group argued that the use of CWIP/AFUDC shifts the risk of investment from shareholders to ratepayers, especially in regard to construction delays or stoppages, and that CWIP/AFUDC violates principles of intergenerational equity by forcing ratepayers to bear the cost of projects from which they are receiving no benefit.

[44] Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order at 9, 54 (September 3, 2013).

The OAG argued that current CWIP/AFUDC practices violate FERC ratemaking principles, despite compliance with its accounting principles; that they violate the "used and useful" ratemaking standard set forth in Minn. Stat. § 216B.16, subd. 6; that the Company can and should finance projects costing under $25 million from internal funds recovered through rates; and that the AFUDC rate for eligible projects should be set at 2.62% instead of the 6.79% used by the Company.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Company's proposed ratemaking treatment of construction work in progress was consistent with Minnesota law, FERC regulations, and longstanding Minnesota practice. She also found that the Company's use of these accounting devices was appropriate and resulted in just and reasonable rates.

She noted that the Commission is required by statute to "give due consideration" to construction work in progress when determining the rate base upon which a utility is permitted to earn a fair rate of return.[45] She noted that all parties concurred that the Company had demonstrated compliance with FERC accounting requirements, as required by the last rate-case order. She noted that the FERC ratemaking principles that the OAG claimed barred the use of Minnesota's established approach to CWIP/AFUDC applied only to wholesale rates set at the federal level, not to retail rates set at the state level.

She found that following the logic of the OAG's proposal to use FERC ratemaking principles would not result in more reasonable rates and would in fact increase the Company's 2014 revenue requirement by $8.5 million and its 2015 revenue requirement by $12.4 million. She found that the record contained no evidence of any other jurisdiction using the CWIP/AFUDC approach the OAG recommended.

The ALJ found that it would not be reasonable to limit the Company's use of CWIP/AFUDC to projects costing more than $25 million, excluding 62% of its capital projects in the 2014 test year. (The Company currently uses CWIP/AFUDC for projects costing more than $25,000 that take longer than 30 days to complete.) She found that the record did not demonstrate that the Company had excess revenues sufficient to fund these projects without external financing.

She found that it would not be reasonable to reduce the Company's AFUDC rate from the 6.79% used by the Company to the 2.62% recommended by the OAG. The 6.79% figure is calculated in accordance with the FERC formula, which first recognizes the cost of short-term debt and then the weighted average of the cost of long-term debt and equity. The 2.26% figure is the average of the Company's short-term and long-term debt rates and relies in part on the assumption that interim-rate over-collections are available to help finance capital projects.

The Administrative Law Judge found that the Company clearly uses equity to help fund capital projects and that interim-rate overcollections are of limited usefulness, since they are refunded with interest under Minn. Stat. § 216B.16, subd. 3(c).

[45] Minn. Stat. § 216B.16, subd. 6.

D. Commission Action

The Commission concurs in the Administrative Law Judge's detailed and reasoned analysis of this issue and will continue to permit the use of CWIP and AFUDC in accordance with current practice.

The Commission concurs that the claim that the application of CWIP and AFUDC violates the "used and useful" provisions of Minn. Stat. § 216B.16, subd. 6, is effectively offset by that subdivision's requirement that the Commission give "due consideration" to construction work in progress when determining rate base:

> *In determining the rate base upon which the utility is to be allowed to earn a fair rate of return, the commission shall give due consideration* to evidence of the cost of the property when first devoted to public use, to prudent acquisition cost to the public utility less appropriate depreciation on each, *to construction work in progress*, to offsets in the nature of capital provided by sources other than the investors, and to other expenses of a capital nature. For purposes of determining rate base, the commission shall consider the original cost of utility property included in the base and shall make no allowance for its estimated current replacement value.[46]

The Commission also concurs that the record does not demonstrate any public-policy or practical advantage to be gained by changing its existing approach to CWIP/AFUDC. The intergenerational impact of current ratepayers' contributions to financing pending projects is effectively counterbalanced by previous ratepayers' contributions to financing pending—and now completed—projects.

Similarly, the Commission concurs with the ALJ's analysis and rejection of the proposals to reduce the 6.79% AFUDC rate, to limit the use of CWIP/AFUDC to projects costing at least $25 million, and to apply FERC wholesale ratemaking principles—or some variation of those principles—to Minnesota CWIP/AFUDC practices. The Commission likewise rejects the claim that the Company has excess revenues with which it can and should finance capital projects costing less than $25 million; it concurs with the ALJ that interim rates are not set to include costs of this nature and magnitude.

For all these reasons, explained in greater detail by the Administrative Law Judge, the Commission concludes that the existing treatment of Xcel's construction work in progress properly reflects the due consideration required by statute.

XXI. Fuel-Clause Revision

A. Introduction

The Company recovers some 30% of its annual gross revenues through the "fuel clause," the automatic rate adjustment authorized under Minn. Stat. § 216B.16, subd. 7, and Minn. R.

[46] Minn. Stat. § 216B.16, subd. 6 (emphasis added).

7825.2390 to .2920 to permit utilities to recover the amount by which their fuel and purchased-power costs exceed the amount built into base rates.

Under Minn. R. 7825.2900, the Company makes a filing before each automatic rate change. Under Minn. R. 7825.2820, the Company makes an annual filing on September 1 explaining and supporting all rate adjustments made through the fuel clause between July 1 and June 30 of the preceding year. Under Minn. R. 7825.2390, the Department files an annual evaluation of Xcel's and every other utility's use of the fuel clause.

The Commission examines the prudence and reasonableness of fuel-clause rate adjustments based on these annual filings.

B. Positions of the Parties

The Chamber and XLI argued that the structure and operation of the fuel-clause adjustments need revision to provide more accountability, greater ease of review, and more effective incentives to minimize fuel and purchased-power costs. They argued that the complexity of fuel and purchased-power costs and the time lag between when they are incurred and when they are reviewed makes effective review difficult.

The Department contended that the fuel clause, as currently designed, weakens utilities' incentive to minimize energy costs and that after-the-fact investigation of these costs is inefficient and difficult.

The Chamber recommended requiring Xcel to file a proposal for a revised fuel clause with its next rate-case filing, unless the Commission has taken action on fuel-clause revision before that time. XLI recommended requiring Xcel to file a new fuel-clause proposal as part of its next rate-case filing or 90 days from the date of the final order in this case, whichever occurs earlier.

The Department concurred on the need for revised fuel-clause procedures but recommended examining the issue in the pending fuel-clause docket where it is under consideration.[47]

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Chamber and XLI raised valid concerns, but found that the issue should be examined in the fuel-clause docket, because the issue involves all utilities operating in the State of Minnesota.

D. Commission Action

The Commission concurs with the Administrative Law Judge.

The issues raised by the Chamber and XLI are policy issues of great importance that affect all Minnesota utilities; they can be most effectively examined in the industry-wide fuel-clause proceeding. While company-to-company facts and issues may vary, industry-wide trends are important, and individual companies' experiences will help inform the analysis of how best to use this statewide regulatory tool.

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[47] *In the Matter of the Review of the 2011–2012 Annual Automatic Adjustment Reports for All Electric Utilities*, Docket No. E-999/AA-12-757.

The Commission finds that this issue is best addressed in the pending fuel-clause proceeding.

XXII. Cost of Replacement Power During Sherco 3 Outage

A. The Issue

In November 2011, an accident at the Company's largest power plant, the Sherburne County Generating Station, or "Sherco," forced the shutdown of one of its three units, Sherco 3. Sherco 3 is a 900 MW coal-fired generator first put into service in November 1987; it is the largest generator in Xcel's system. Damage to the generator was massive, and it remained shut down from November 2011 to October 2013.

To replace Sherco 3's output, Xcel bought both replacement power and additional fuel for Company-owned generators capable of increasing their output to help meet the deficit; these costs were passed on to ratepayers through the "fuel clause," the Company's automatic rate adjustment for changes in energy costs.[48] The Chamber recommended requiring the Company to capitalize the amount by which these costs exceeded what would have been the costs of uninterrupted Sherco 3 generation and to recover these excess costs over the remaining life of the unit.

The Company and the Department said that all issues regarding the recoverability and ratemaking treatment of these costs were being addressed in two proceedings examining utilities' 2011–2013 fuel-clause rate adjustments and should be decided there.[49] The Administrative Law Judge concurred.

B. Commission Action

The Commission agrees that the ongoing annual fuel-clause-adjustment dockets are the best places to examine these issues and will not address them here.

Under Minn. R. 7825.2390 to .2920, utilities file detailed monthly and annual reports on all automatic rate adjustments made through the fuel clause. These filings receive careful review by interested stakeholders and by the Department, which files a report analyzing the year's fuel-clause activity and highlighting any concerns with accuracy, prudence, or related issues. The Commission holds an annual meeting to examine and act on the utilities' annual reports.

The causes of the Sherco 3 accident and the adequacy and prudence of the Company's response are being examined in the pending fuel-clause dockets for the nearly two-year period of the Sherco 3 outage. Those two proceedings focus on the issues raised by the Chamber of Commerce, and those two proceedings are a more efficient means for comprehensively examining them. The Commission concurs with the Administrative Law Judge that those issues should be addressed there, not here.

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[48] Minn. Stat. § 216B.16, subd. 7.

[49] *In the Matter of the Review of the 2011–2012 Annual Automatic Adjustment Reports for All Electric Utilities*, Docket No. E-999/AA-12-757 and *In the Matter of the Review of the 2012–2013 Annual Automatic Adjustment Reports for All Electric Utilities*, Docket No. E-999/AA-13-599.

XXIII. Cost of Replacement Fuel During Black Dog Outage

A. The Issue

From December 23, 2012, to March 10, 2013, two generating units at the Company's Black Dog power plant were out of service because of an accident caused by human error. During that time the Company incurred additional capital costs of some $24,104, additional operation and maintenance costs of about $1.838 million, and additional fuel-replacement costs in an amount that has been designated trade secret. The additional fuel-replacement costs were passed on to ratepayers through the Company's automatic rate adjustment for changes in the cost of fuel, the "fuel clause."

XLI recommended that test-year operations and maintenance costs be reduced by $1.838 million, that the $24,104 capital investment be removed from rate base, and that the replacement-fuel costs receive close scrutiny in the pending proceeding examining the Company's automatic rate adjustments through the fuel clause.[50] The Company agreed that replacement-fuel costs should be examined in the 2012–2013 fuel-clause adjustment docket, but pointed out that the other costs were incurred outside the test year and were not reflected in test-year costs.

The Administrative Law Judge concurred with the Company. She found that there was no basis for disallowing costs that were not in the test year and that such a disallowance would constitute retroactive ratemaking. She found that XLI had an opportunity to raise this issue in the Company's last rate case and had not done so. She concurred with both parties that the recoverability of the additional fuel-replacement costs was properly before the Commission in the annual fuel-clause adjustment docket.

B. Commission Action

The Commission concurs with the Administrative Law Judge and accepts and adopts her findings, conclusions, and recommendation. The costs associated with the Black Dog outage were incurred outside the test year and are not included in the test-year revenue requirement sought by the Company. The issue of the recoverability of the additional replacement-fuel costs is properly before the Commission in the 2012–2013 annual fuel-clause adjustment docket and will be examined there.

XXIV. Babcock & Wilcox Litigation

A. Introduction

In a January 20, 2015 letter, the OAG brought to the Commission's attention a pending lawsuit with the Company as a named defendant, filed after the evidentiary hearing in this case had concluded. The plaintiff, Babcock & Wilcox Nuclear Energy, Inc., is a subcontractor involved in the replacement-steam-generator project at the Prairie Island generating plant. At issue is a dispute over $45.3 million that Babcock & Wilcox asserts it is owed for its work, along with interest on the disputed amount if Babcock & Wilcox prevails.

[50] Docket No. E-999/AA-13-599.

B. Positions of the Parties

1. The OAG

The OAG expressed concern that the disputed amount was included in the Company's rate base despite having been withheld from payments to Babcock & Wilcox. The OAG argued that the Company should be required to disclose the contracts at the center of the dispute to the OAG, and provide additional discussion, analysis, and information supporting all costs and interest paid to Babcock & Wilcox when the lawsuit is resolved. As an alternative to requiring the disputed $45.3 million to be excluded from rate base, the OAG supported refunding any costs included in rate base but not paid.

2. The Department

The Department generally supported the OAG's position and recommendations. The Department stated that it was concerned about how a refund would work, especially if the litigation was not resolved by the time 2014 and 2015 refunds agreed to by the Company or required by the Commission were to be calculated.

3. The Company

Xcel acknowledged the litigation and the underlying dispute with Babcock & Wilcox. It asserted that the contracts sought by the OAG were subject to confidentiality provisions limiting their disclosure. The Company argued that a favorable litigation outcome would benefit ratepayers, and agreed to address the disputed amount as part of the 2014 Plant Related Revenue Requirement True-Up process.

The Plant Related Revenue Requirement True-Up process was listed as an issue resolved between the Company and the Department, and was not presented as a disputed issue for resolution by the ALJ or the Commission. The Company has agreed to refund the difference between the Commission-approved revenue requirements and actual revenue requirements associated with capital additions in 2014 and 2015.[51]

C. The Recommendation of the Administrative Law Judge

Because this issue arose after the close of the evidentiary proceeding, the ALJ did not consider it.

D. Commission Action

The Commission will require that the Company refund disputed costs included in rate base but not used to pay for the Prairie Island replacement-steam-generator project. But the Commission will allow the litigation to run its course before requiring any true-up. To address the OAG's and the Department's concerns about how the true-up process will work, the Commission will impose additional procedural and filing requirements.

Once the lawsuit is resolved, the Company must make a compliance filing providing all relevant information as to costs and interest paid to Babcock & Wilcox and discuss what costs were included

[51] October 7, 2014 Issues List at 34–35.

as Plant in Service in the current rate case. Any costs included in rate base but not paid will be refunded to ratepayers as part of either the 2014 or 2015 refund, and if the lawsuit is not resolved at either of those times, then the refund will be made within 60 days after the lawsuit is resolved.

Within 30 days of completing the refund, the Company will be required to make a compliance filing with information detailing the refund and the resolution of the lawsuit. In the filing, the Company will describe the amount not paid to Babcock & Wilcox that remains in rate base and the revenue-requirement effect of that amount so the Commission can consider whether to require Xcel to track that amount for return to ratepayers in Xcel's first rate case after the resolution of the lawsuit.

XXV. Rate-Moderation Proposals

The Company proposed two measures to moderate the rate impact of its 2014 and 2015 revenue deficiencies:

- It proposed to accelerate the eight-year amortization ordered in its last rate case of the surplus in its transmission, distribution, and general-plant depreciation reserve by amortizing 50% of the remaining surplus in 2014, 30% in 2015, and 20% in 2016; and
- It proposed to reduce the 2015-Step increase by the approximately $25.7 million by which its 2013 and 2014 nuclear-waste-storage settlement payments from the U.S. Department of Energy exceeded the amounts required for 2013 and 2014 nuclear-decommissioning-fund accruals.

The Commission will adopt both measures, as discussed individually below.

A. Accelerating the Amortization of Transmission, Distribution, and General-Plant Depreciation Surplus

1. Introduction

In Xcel's last rate case, the Commission directed the Company to amortize over eight years a surplus of some $265 million in its transmission, distribution, and general-plant depreciation accounts.[52] In this case, the Company proposes to accelerate that amortization to moderate the rate increases sought here; it proposes to amortize 50% of the remaining surplus in 2014, 30% in 2015, and 20% in 2016.

2. Positions of the Parties

The Department did not oppose the Company's proposal but preferred slightly different amortization percentages in years two and three. The Department recommended a 50/40/10 split instead of the 50/30/20 split recommended by the Company, largely because the 50/40/10 split would mean smaller rate increases in the 2015 Step. In the alternative, the Department supported the Company's proposed split of 50/30/20.

The Company cautioned against reducing the 2016 depreciation-amortization surplus, when it could potentially play a significant role in moderating increases sought in future rate cases.

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[52] Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order at 25–29 (September 3, 2013).

The Xcel Large Industrials supported the Company's proposal.

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the determination of whether to adopt either or both of the Company's two rate-moderation proposals would depend on the size of the 2014 and 2015-Step revenue deficiencies found by the Commission. She found that accelerating the amortization of the depreciation surplus would reduce rates in the short term but result in higher rates in later years.

She found that there may be circumstances in which acceleration would be warranted to avoid rate shock or to address intergenerational equity. She noted that the Company's accelerated-amortization proposal had been factored into interim rates, which she found might make some form of continued acceleration reasonable.

4. Commission Action

The Commission finds that the revenue deficiencies and resulting rate increases for the 2014 test year and the 2015 Step, while necessary and reasonable, are large enough and close enough in time to the last rate increase to merit the accelerated-amortization moderation measure recommended by the Company. The Commission will therefore require accelerated amortization of the transmission, distribution, and general-plant depreciation surplus, using the amortization schedule recommended by the Company.

This approach will provide a measure of rate relief as to both the 2014 and 2015-Step rate increases. It will appropriately direct greater relief to the first and higher increase, especially in light of the application of the Department of Energy settlement funds to the 2015-Step increase, as discussed below. It will smooth the transitions from current rates to 2014 rates to 2015-Step rates. And it will accomplish these goals without exhausting the amortization surplus, potentially contributing to future rate stability.

Further, this approach will serve the ratemaking goal of intergenerational equity by ensuring a closer match between the subset of ratepayers whose rates reflected inflated depreciation costs and the subset of ratepayers whose rates will reflect the return of those overpayments.

For all these reasons, the Commission concludes that the amortization of the depreciation surplus should be accelerated and should follow the 50/30/20 split recommended by the Company.

B. Applying 2013 and 2014 Settlement Payments from the Department of Energy to the 2015-Step Increase

1. Introduction

Xcel proposed to reduce the 2015-Step increase by applying to the 2015-Step revenue deficiency the approximately $25.7 million by which its 2013 and 2014 nuclear-waste-storage settlement payments from the U.S. Department of Energy (DOE) exceeded the amounts required for 2013 and 2014 nuclear-decommissioning-fund accruals.[53]

2. Positions of the Parties

The Department did not oppose applying the DOE settlement payments to the 2015-Step revenue deficiency to offset the resulting rate increase.

The Commercial Group recommended using the DOE funds to offset both the 2014 and the 2015-Step rate increases, applying the 2013 settlement payment toward the 2014 increase and the 2014 payment toward 2015-Step increase. The Group argued that this approach appropriately balanced the goals of rate moderation and timely return of ratepayer funds.

The Company recommended applying both DOE payments to the 2015-Step increase to moderate the impact of amortizing a lower percentage of the depreciation surplus in 2015 than in 2014, as discussed above.

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the determination of whether to adopt either or both of the Company's two rate-moderation proposals would depend on the size of the 2014 and 2015-Step revenue deficiencies found by the Commission.

She recommended applying the DOE funds to rate relief if the Commission found a need for rate moderation and declined to make a recommendation on whether the funds should be distributed between the 2014 and 2015-Step revenue deficiencies or applied to only one.

4. Commission Action

The Commission finds that the revenue deficiencies and resulting rate increases for the 2014 test year and the 2015 Step, while necessary and reasonable, are large enough and close enough in time to the last rate increase to merit the DOE-payments moderation measure recommended by the Company. The Commission will therefore require the application of the DOE 2013 and 2014 settlement payments to the 2015-Step revenue deficiency, in addition to the 30% portion of the unamortized depreciation surplus discussed above.

While applying just one of the two DOE payments to the 2015 Step would also bring some rate relief in 2015, applying both payments will obviously deliver more, and will cushion the impact of applying a smaller portion of the unamortized depreciation surplus to the 2015 Step than the 2014 test year. It will better serve the ratemaking goals of maintaining rate stability and avoiding rate shock. Where, as here, a utility is near the peak of a demanding investment cycle, with rate increases recurring at shorter-than-average intervals, it is reasonable to smooth the rate impact of that peak with the tools at hand, disrupting customers' settled rate expectations as little as possible.

[53] These payments reflect the outcome of litigation against the Department of Energy for increasing the Company's nuclear-waste storage costs by failing to assume responsibility on schedule for the storage of nuclear waste.

For all these reasons, the Commission concludes that the DOE settlement payments for 2013 and 2014 should be applied to the 2015-Step revenue deficiency, in addition to the 30% of the unamortized depreciation surplus discussed above.

COST OF CAPITAL ISSUES

XXVI. Cost of Equity

A. Introduction

In determining just and reasonable rates, the Commission is required to

> give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, *and to earn a fair and reasonable return upon the investment in such property*.[54]

One of the critical components of that fair and reasonable return upon investment is the return on common equity, which—together with debt—finances the utility infrastructure. The Commission must set rates at a level that permits stockholders an opportunity to earn a fair and reasonable return on their investment and permits the utility to continue to attract investment.

In short, the Commission must determine a reasonable cost of equity and factor that cost into rates. It would normally begin by examining the price of the utility's stock, but Xcel is a subsidiary of Xcel Energy, Inc. and has no publicly traded common stock. Its cost of common equity—essential to determining overall rate of return and the final revenue requirement—must therefore be inferred from market data for companies that present similar investment risks.

B. The Analytical Tools

Xcel, the Department, and the ICI Group conducted cost-of-equity studies and based their analysis on comparison groups of utilities they considered similar enough to Xcel to serve as proxies in determining the Company's cost of equity. All three used the Discounted Cash Flow (DCF) analytical model, on which this Commission has historically placed its heaviest reliance.

The Company and the Department also used the Capital Asset Pricing Model (CAPM) as a secondary, corroborating resource, consistent with the Commission's historical treatment of this model. The Company also conducted a third analysis using the Bond Yield Plus Risk Premium Model, which the Commission has historically relied on less heavily, considering the model prone to producing volatile and unreliable outcomes.

The DCF model uses the current dividend yield and the expected growth rate of dividends to determine what rate of return is high enough to induce investment. The model is derived from a

[54] Minn. Stat. § 216B.16, subd. 6 (emphasis added).

formula used by investors to assess the attractiveness of investment opportunities using three inputs—dividends, market equity prices, and growth rates.

The CAPM model estimates the required return on an investment by determining the rate of return on a risk-free, interest-bearing investment; adding a historical risk premium determined by subtracting that risk-free rate of return from the total return on all market equities; and multiplying the remainder by beta, a measure of the investment's volatility compared with the volatility of the market as a whole.

The Bond Yield Plus Risk Premium Model determines the cost of equity by adding to current corporate bond yields a premium reflecting the greater returns realized by equity holders over various historical periods.

C. Positions of the Parties

1. The Company and the Department

Xcel recommended a return on equity of 10.25%, and the Department recommended a return on equity of 9.64%

The Company and the Department both conducted full-scale DCF analyses, each using two comparison groups of utilities screened for comparability with Xcel in terms of operating profiles and investment risks. One comparison group was made up of electric utilities and the other of utilities with both gas and electric operations.[55] The Company's electric group and combined group each consisted of 14 companies; the Department's electric group consisted of ten companies and its combined group of 14 companies. The parties' comparison groups contained many of the same companies.

Both parties conducted DCF analyses on all companies in both groups, using information from three nationally recognized investment-research firms—Value Line, Zack's, and First Call—for growth-rate estimates. Both added flotation costs (the fees and expenses incurred in issuing securities) of 2.926% to their results. Both filed updated DCF analyses at the end of the evidentiary hearings based on the most recent information available.

Both parties' updated DCF results were lower than their initial results, and the Department lowered its initial recommended return of 9.8% to 9.64%. This number was the midpoint of its updated DCF results for all companies in both its comparison groups, which it weighted 60/40 between the electric-utility and combined-utility groups. The update was based on the 30-day period between June 7 and July 7, 2014.

The Company continued to recommend 10.25%. This number was higher than the midpoint of its updated DCF results for all companies in both its comparison groups, which it weighted 80/20 between the electric-utility and combined-utility groups. The Company's update, like its initial analysis, was based on averaging stock closing prices over 30-day, 90-day, and 180-day periods, instead of the single 30-day period used by the Department.

[55] Xcel is a combined utility, with 91.67% of its net income derived from electric operations and 8.33% from gas operations. Ex. 28 (Hevert Rebuttal) at 19.

The Company argued that, given its need for major capital expansion in the near term—especially in transmission and renewable generation—it was important for the Commission to set the cost of equity at a level demonstrating strong regulatory support for the Company, to ensure continued access to capital at favorable rates. It argued that setting the return on equity below the 9.83% set in the last rate case would send the opposite signal to investors, especially since this would be the second consecutive rate case in which its cost of equity declined. The Company also argued that the multiyear rate plan would reduce its ability to react to changing market conditions, which it argued was especially concerning given what it perceived to be current volatility in the financial markets.

Finally, the Company pointed to rates of return on equity above the 9.64% recommended by the Department awarded in other jurisdictions and in earlier cases in this state.

2. The ICI Group

The ICI Group recommended a return on equity of 9%.

The ICI Group conducted four variants of the DCF analysis using one comparison group of 27 utilities. This group consisted of all companies classified as electric utilities by Value Line, minus those with no expected growth in earnings or dividends during the study period, those that had not consistently paid dividends over the past three calendar years, those known to be currently involved in mergers, and those whose principal business was transmission of electricity, not retail sales.

The Group's analysis relied on investment data from Value Line and was not subjected to check by any alternative analytical model. The Group questioned the value of using the CAPM or Bond Yield Plus Risk Premium models as checks as the Company and Department did, arguing that the Federal Reserve's intervention in current debt markets undermined the accuracy of current interest rates as indicators of true market conditions.

The Group pointed to returns on equity recently granted in other jurisdictions as evidence of the broad range of reasonable returns. The Group opposed recovery of a flotation adjustment on the grounds that the Company would not be issuing securities during the period the new rates would be in effect.

3. The Commercial Group

The Commercial Group did not recommend a specific return on equity but said the return should not exceed the 9.64% recommended by the Department.

The Commercial Group did not conduct a cost-of-equity study but pointed to factors that it argued reduced investment risk, thereby reducing the reasonable return on equity: the use of a future test year, the use of interim rates, the inclusion of CWIP in rate base, the second-year rate increase built into the multiyear rate plan, and the proposed revenue decoupling mechanism.

The Commercial Group also emphasized the broad range of returns granted in other jurisdictions and argued that the return in this case should not exceed the 9.64% recommended by the Department.

4. AARP

AARP argued that the cost of equity should be adjusted downward, to reflect reduced risk, if the Commission authorized revenue decoupling.

D. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that both Xcel and the Department had conducted fundamentally sound DCF studies meriting careful consideration. These studies formed the foundation for her analysis, which resulted in a recommended return on equity of 9.77%.

She derived this number by averaging the results in the Department's direct testimony, the Company's rebuttal testimony,[56] and the Department's surrebuttal testimony. These results represented three separate periods: October 1–31, 2013; May 1–30, 2014; and June 7–July 7, 2014, and each was based on the most recent information then available. The Department had followed its standard practice of recommending adoption of its final (surrebuttal) DCF outcome, in reliance on the economic principle that the most recent information is normally the best indication of future market performance.

The ALJ disagreed. She found that using a single 30-day period could lead to anomalous results and that the June 7–July 7, 2014 data on which the Department based its final recommendation might represent a short-term anomaly. She found that stock prices were unusually high during that 30-day period and that the Department's surrebuttal data might not be representative of the period during which the new rates would be in effect.

She found that the multiyear impact of this two-year rate plan compounded the need to ensure that market idiosyncrasies did not affect outcomes. She also found that 9.77% was the average return on equity in four 2014 rate cases in other states and that a return higher than the one recommended by the Department would help the Company attract the investment it needed for upcoming capital outlays.

She weighted the electric-utility and combined-utility comparison groups at the 60/40 ratio recommended by the Department, not the 80/20 ratio recommended by the Company. She found that the 60/40 ratio was consistent with past practice and that the critical element to ensure a valid comparison group was similar investment risk, not similar operations. She also noted that Xcel's parent company had subsidiaries with both gas and electric operations.

The ALJ recommended permitting the recovery of flotation costs as consistent with longstanding practice and necessary to ensure that the Company was not denied the opportunity to earn its authorized rate of return.

She recommended granting no weight to the ICI Group's cost-of-equity study, finding that the companies in the comparison group were not sufficiently comparable to Xcel and that the use of a single source of market and investment data was insufficiently rigorous. She also rejected one of the study's DCF variants—the sustainable-growth analysis—as not widely accepted, biased downward, and based on questionable assumptions.

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[56] She used the Company's 30-day DCF results.

The ALJ rejected claims that the return on equity should be reduced to reflect risk reductions attributable to the availability of interim rates, the inclusion of CWIP in rate base, or the use of a future test year, finding that these were routine Minnesota regulatory practices and had therefore already been taken into account by investors. Further, she found that these ratemaking tools were available to many of the utilities in the comparison groups, making investment risks similar.

She rejected the claim that revenue decoupling would necessitate a reduction in the cost of equity, for three reasons. First, many of the companies in the comparison group had decoupling rate designs, demonstrating the similarity in investment risk required for a reliable DCF analysis.

Second, the record contained a study by a national research and consulting group showing "no significant evidence of a decrease in the cost of capital following adoption of decoupling."[57] And finally, the Company's cost-of-equity expert witness provided a detailed analysis of a representative company's extensive and long-term experience with decoupling, which demonstrated that decoupling had no measurable impact on its cost of capital.[58]

E. Commission Action

1. Introduction

As explained below, the Commission will set the cost of equity at 9.72%, the midpoint of the Department's updated DCF results for its electric-utility comparison group.

The Commission concurs with the Administrative Law Judge that the Company's and the Department's cost-of-equity studies are methodologically transparent, analytically sound, and ably executed. Together they represent the best evidence in the record on the cost of equity and provide a workable framework for determining where to set the cost of equity in this case.

As the ALJ pointed out, the main differences between the two parties' DCF analyses were the time period used to determine the dividend-yield input and the relative weight given the DCF results of the electric-utility and combined-utility comparison groups. On the first issue, the ALJ accepted the Company's proposal to average data from more than one 30-day period over the Department's proposal to average data from the most recent 30-day trading period; on the second issue she accepted the Department's 60/40 ratio over the Company's 80/20 ratio.

The Commission does not concur with the ALJ on these two issues and will not accept all her findings, conclusions, and recommendations on them. The Commission will instead base the cost of equity on investment data from the most recent 30-day period in the record and will use data from the electric-utility comparison group only. These determinations yield a return on equity of 9.72%.

On all other issues the Commission accepts and adopts the findings, conclusions, and recommendations of the Administrative Law Judge. These determinations are further explained below.

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[57] ALJ's Report ¶ 389.

[58] *Id.*

2. Time Period for Averaging Data to Update DCF Analysis

The Department made the final update to its DCF analysis using averaged data from the most recent 30-day trading period for which investment data was available. The Company made its final update using averaged data from the most recent 30-day, 90-day, and 180-day trading periods for which investment data was available. The Administrative Law Judge concurred in the Company's multi-period averaging approach.

She found that, although the most recent 30-day trading period was normally the best reflection of the current market expectations used to set the cost of equity,[59] in this case abnormally high stock prices during that period made longer-period averaging a better choice:

> In this case, however, the Administrative Law Judge concludes that the record shows that the 30-day period used in the Department's Surrebuttal testimony may not be representative of the time period in which the ROE will remain in effect. More specifically, the record shows that the dividend yields used in the Department's Surrebuttal Testimony were significantly lower than the dividend yields used in its Direct Testimony, falling by 54 and 26 basis points, respectively, from the Department's initial analysis. These decreased dividend yields were the result of unusually high stock prices during the June-July 2014 time period used in the Department's Surrebuttal Testimony. Since that time, utility stock prices have declined relative to the overall stock market and moved more in line with historic expectations. As a result, the Department's updated 30-day dividend yields included in its Surrebuttal Testimony may reflect a short-term anomaly.[60]

She therefore averaged the DCF results in the Department's direct testimony, the Company's rebuttal testimony, and the Department's surrebuttal testimony—each representing a different 30-day trading period—yielding a cost of equity of 9.77%. She concluded that this number not only corrected for the abnormally high stock prices that had skewed the Department's updated DCF results, but (a) was more reasonable in light of the extended time period the rates would be in effect under the multiyear rate plan, and (b) would facilitate the Company's access to capital on favorable terms by avoiding the potentially negative signal the lower cost of equity proposed by the Department could send to investors.

The Commission disagrees on all three counts.

a. Multiple-Period Averaging Rejected

First and most important, there is no support in the record for the finding that stock prices were unusually high during the June 7–July 7 trading period, nor for the finding that utility stock prices declined relative to the overall stock market between that period and the December 26 filing of the Administrative Law Judge's Report.

[59] *Id.* ¶ 380.

[60] *Id.* ¶ 382 (citations omitted).

These are factual claims for which the Administrative Law Judge cites only the Opening Statement made at the evidentiary hearing by the Company's cost-of-equity witness. That Statement neither contains nor points to any hard data or technical analysis purporting to prove these claims; it simply states them as if they were common knowledge.

As the Department pointed out in its briefs and exceptions, however, neither claim is common knowledge, and neither claim can be proved by expert testimony without supporting facts and analysis. Further, the Department contested both claims on the merits, with as much record support as the Company. Since there is no reliable evidence that the trading period used in the Department's updated DCF analysis is aberrant and no reliable evidence of a need to average data from multiple trading periods, the Commission rejects finding 382 as unsupported in the record.[61]

That leaves in place the ALJ's finding that the most recent information is normally the most reliable indicator of the current market expectations on which the cost of equity is based.[62] This finding is a restatement of the basic financial principle, followed by the Department, that financial markets are efficient such that the current stock prices fully reflect all publicly available information and are therefore the most reliable source of information on investor expectations. This finding is also consistent with longstanding Minnesota practice.

The Commission concurs and will base its cost of equity on the most recent information in the record, the Department's final DCF analysis.[63]

b. Secondary Rationales Rejected

The Commission also rejects the secondary rationales that the ALJ found supported the higher return resulting from multiple-period averaging—the 9.77% average return granted in other rate cases in other states, the need to demonstrate strong regulatory support for Xcel to facilitate access to capital on favorable terms, and the need to hedge against the possibility of the cost of equity being too low as the term of the multiyear rate plan wears on.

As to the first issue, the Commission sees little probative value in the four 2014 cost-of-equity decisions in other states cited by the ALJ, since these decisions were by definition specific to the circumstances of individual utilities, their service areas, and then-prevailing economic conditions.

As to the second issue, the Commission remains persuaded that utility investors are prudent and sophisticated investors who value regulatory stability, predictability, and integrity above specific

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[61] In its reply brief and exceptions the Department also pointed to hard data from publicly available sources that it argued demonstrated that both claims were factually wrong. The Company did not object to these submissions, but they are not in the evidentiary record and have not been subject to analysis and cross-examination by other parties. *See* Reply Brief of the Department at 6–8; Exceptions at 8–14.

[62] ALJ's Report ¶ 380.

[63] The Company and the ALJ note that the Commission has on rare occasions averaged more than one trading period to smooth final DCF outcomes, most notably in the last MERC rate case. *In the Matter of a Petition by Minnesota Energy Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G-011/GR-13-617, Findings of Fact, Conclusions, and Order (October 28, 2014). They are correct, but that decision, like all rate-case decisions, was fact-specific and based on that gas utility's unique operational and financial situation, as well as the state of the economy at the time of the determination.

outcomes. The 9.72% return on equity reflects the assiduous application of sound economic models and accepted regulatory and legal principles to a solid evidentiary record; this is a signal of strong regulatory support for Xcel and other Minnesota utilities.

As to the third issue, the Commission concurs with the Department that the Company chose to file a multiyear rate plan and can therefore be presumed to have found it in its best interests. Further, there is no good evidence, analytical or factual, on the impact of multiyear rate plans on rates of return. The Commercial Group argued that the multiyear rate plan, with its guaranteed second-year rate increase, reduced Xcel's investment risk and should therefore reduce its return on equity.[64] The Department argued that rates of return were equally likely to go up or down during the term of the rate plan.[65]

Finally, in its Multiyear Rate Plan Order, the Commission found that the rate of return would be set on the basis of test-year data and applied throughout the term of the multiyear plan; no other approach had evidentiary support or even appeared to be practicable.[66] For all these reasons, the Commission concludes that it is not reasonable to treat the multiyear rate plan as a factor requiring a higher return on equity.

3. Weighting the Electric-Utility and Combined-Utility Comparison Groups

Both Xcel and the Department used two comparison groups, one of electric utilities and one of combined gas-and-electric utilities. The Department weighted the DCF results of the two groups 60/40 electric group/combined group; the Company weighted them 80/20 electric group/combined group.

The Administrative Law Judge accepted the 60/40 weighting recommended by the Department, for three reasons: (1) it was consistent with past practice, (2) the critical element to ensure a valid comparison group is similar investment risk—which the record demonstrated—not similar operations, and (3) Xcel's parent company has subsidiaries with both gas and electric operations.

The Commission will base its return on equity on the Department's DCF results for its electric comparison group, finding that that comparison group most closely matches the Company's situation. As stated earlier, the Company derives 91.67% of its net income from electric operations and 8.33% from gas operations;[67] The Department's electric comparison group on average derived 90% of its net income from electric operations, while the comparable number for its combined group was only 78.39%.

Since the electric group, like the combined group, was carefully screened for investment risk similar to Xcel's—comparing factors such as volatility of rates of return, common-equity ratios, long-term debt ratios, and bond ratings—it is clearly a valid comparison group. And since it more closely resembles Xcel in the significant category of operational profile, it is a better match for analytical purposes.

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[64] Initial Brief of Commercial Group at 9.

[65] Reply Brief of Department at 8; Exceptions at 13.

[66] Docket No. E,G-999/M-12-587.

[67] Ex. 28 (Hevert Rebuttal) at 19.

The fact that Xcel's parent company holds other subsidiaries with combined gas and electric operations does not affect this determination, since there is no evidence in the record that the operational profiles of these other subsidiaries have any effect on Xcel's investment risk. And past practice is not determinative; not only is the issue of Xcel's past investment risk vis-à-vis other combined utilities not developed in this record, but past practice must and should yield to current realities.

The Commission will therefore use the Department's electric comparison group in setting the Company's cost of equity in this case.

4. Conclusion

For all these reasons, the Commission will set the cost of equity at 9.72%, the midpoint of the Department's updated DCF results for its electric-utility comparison group.

XXVII. Capital Structure and Overall Cost of Capital

The Company and the Department agreed on the Company's capital structure for both the 2014 test year and the 2015 Step. The ICI Group initially argued that the equity component of the Company's capital structure should be the same as the equity component of its parent company, Xcel Energy, Inc., but it did not ultimately include that claim among the modifications it recommended to the ALJ's recommendations.[68]

The Company and the Department agreed on the cost of long- and short-term debt for both the 2014 test year and the 2015 Step; no other party commented. The Administrative Law Judge concurred in the Department and the Company's joint recommendation on both capital structure and the cost of debt, as does the Commission.

The Company, the Department, the ICI Group, the Commercial Group, and AARP disagreed on the cost of common equity. As explained above, the Commission has set the cost of equity at 9.72%.

The resulting overall capital structure and cost of capital are set forth below, rounded to the second decimal place:

2014 Test Year

Component	Component Ratio	Cost	Weighted Cost
Long-term Debt	45.6%	4.90%	2.23%
Short-term Debt	1.9%	0.62%	0.01%
Common Equity	52.5%	9.72%	5.10%
Total	100%		7.35%

[68] ICI Exceptions at 41–42.

2015 Step

Component	Component Ratio	Cost	Weighted Cost
Long-term Debt	45.61%	4.94%	2.25%
Short-term Debt	1.89%	1.12%	0.02%
Common Equity	52.5%	9.72%	5.10%
Total	100%		7.38%

CLASS COST OF SERVICE STUDY ISSUES

XXVIII. Class-Cost-of-Service Study

A. Background

As required by rule, the Company's rate-case filing included class-cost-of-service studies for the 2014 test year and the 2015 Step.[69] The 2015 study reflects an additional $98.4 million in revenue requirements for the 2015-Step increase.

The purpose of a class-cost-of-service study is to determine, as accurately as possible, the costs of serving each customer class. While these costs cannot be determined with precision, it is critical that the study make both its underlying assumptions and the cost figures they yield as accurate and transparent as possible, because the Commission puts substantial weight on cost causation in determining what portion of the total revenue requirement each customer class should pay.

Parties challenged various aspects of Xcel's studies: (1) the classification of the fixed costs of the Company's production plant, (2) the classification of the fixed costs of certain Company-owned wind farms, (3) the allocation of capacity costs among customer classes, (4) the classification of certain nonfuel O&M costs, and (5) the allocation of distribution costs.

Each challenge is addressed below.

B. Classifying Fixed Production Plant

1. Introduction

Xcel divided its fixed production-plant costs into capacity-related and energy-related subfunctions using a process called the "plant stratification method." The Company has used this method to classify fixed production-plant costs since the 1970s.

Under the plant-stratification method, Xcel compares the per-kilowatt (kW) cost of each plant type to the per-kW cost of a peaking plant to calculate a capacity and energy percentage for each plant type:

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[69] *See* Minn. R. 7825.4300(C).

Stratification Allocation by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity Percentage	Energy Percentage
Peaking	$770	$770 / $770	100.0%	0.0%
Nuclear	$3,689	$770 / $3,689	20.9%	79.1%
Fossil	$1,976	$770 / $1,976	39.0%	61.0%
Combined Cycle	$1,020	$770 / $1,020	75.4%	24.6%
Hydro	$4,519	$770 / $4,519	17.0%	83.0%

Peaking plants have the lowest capital cost to build but also the highest operating costs. They are therefore used only to meet customer demand at peak times, and their capital cost is assumed to be entirely capacity-related. Per-kW costs that exceed that of a peaking plant are assumed to be energy-related.

After classifying its fixed production-plant costs as capacity- or energy-related, Xcel allocates the costs of the two subfunctions among its customer classes based on the percentage of capacity or energy costs caused by each class.

2. Positions of the Parties

The Chamber recommended that the Company classify fixed production plant using the "straight fixed–variable method." Under the straight fixed–variable method, all fixed production-plant costs are classified as demand-related on the theory that plant capacity is required to meet peak demand. Only variable costs such as fuel are classified as energy-related. The Chamber argued that the straight fixed–variable method should be used based on its view that high-volume energy users are allocated more than their fair share of costs under the plant-stratification method.

The Department disagreed with the Chamber's recommendation, arguing that the plant-stratification method properly reflects the dual value of baseload plants, which provide both capacity and low-cost energy. The Department noted that the Commission chose not to approve this same proposal by the Chamber in Xcel's last rate case.

XLI did not oppose the plant-stratification method but recommended two modifications. Under the plant-stratification method, Xcel compares the current-dollar replacement value of a peaking plant with the current-dollar replacement cost of the other plant types to calculate capacity and energy allocations for each type. XLI argued that Xcel's approach understates the capacity portion of the Company's fixed plant. To correct this, XLI recommended that Xcel use (1) the estimated cost of a new peaking plant instead of its current-dollar replacement value and (2) depreciated replacement values for the other plant types instead of current-dollar replacement values.

Xcel, the Department, and the OAG opposed XLI's modifications to the plant-stratification method. Xcel argued that XLI's approach would result in an apples-to-oranges comparison by mixing the undepreciated costs of a new peaking plant with the depreciated replacement values for the other plant types. The Company maintained that the replacement cost of a peaking plant, not the cost of a new peaking plant, is the relevant cost for study purposes.

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge noted that the Commission has consistently approved the plant-stratification method and concluded that the Chamber had offered no new convincing argument for the straight fixed–variable method or addressed the need to recognize the dual nature of baseload plants. The ALJ concluded that Xcel's use of the plant-stratification method was reasonable.

As to XLI's proposal, the ALJ agreed with the other parties that comparing the cost of a new peaking plant to the depreciated value of other types of generating plants is not analytically sound.

4. Commission Action

The Commission concurs with the ALJ and adopts her conclusion that Xcel's continued use of the plant-stratification method is reasonable.

The Company's method, unlike the straight fixed–variable method advanced by the Chamber, appropriately reflects the fact that Xcel builds baseload plants to meet both demand and energy needs. If Xcel acquired production plants only to meet peak demand at the lowest cost, the Company would be building only peaking plants with the lowest cost per unit of capacity. Instead, Xcel selects a mix of generation facilities with varying capital costs to achieve the dual goals of sufficient capacity and viable energy costs.

Moreover, the Company's method makes appropriate comparisons between the current-dollar replacement cost for a peaking plant and current-dollar replacement costs for other plant types. For this reason, the Commission declines to adopt XLI's recommendation to use (1) the undepreciated cost of a new peaking plant and (2) depreciated replacement costs for other plant types.

C. Classifying the Fixed Costs of Company-Owned Wind Farms

1. Introduction

Xcel included in its class-cost-of-service studies four wind farms that it owns: (1) Grand Meadow, (2) Nobles, (3) Pleasant Valley, and (4) Border Winds.

Grand Meadow and Nobles are older projects that were included in Xcel's last rate case; Pleasant Valley and Border Winds are new projects that are expected to be online by the end of 2015. Accordingly, Grand Meadow and Nobles are included in both class-cost-of-service studies, while Pleasant Valley and Border Winds are only included in the study for the 2015 Step.

In its last rate case, Xcel classified Grand Meadow and Nobles costs on the same basis as its other fixed production-plant costs, using the plant-stratification method. As a result, the two plants were classified as roughly 4–5% capacity-related and 95–96% energy-related. In this case, however, the Company changed its analysis for Grand Meadow and Nobles, classifying the two facilities as 100% capacity-related.

Xcel applied the usual plant-stratification method to Pleasant Valley and Border Winds.

2. Positions of the Parties

Xcel argued that the change in classification methodology for Grand Meadow and Nobles is appropriate because these plants do not fit the resource-selection model that the plant-stratification method is designed to reflect. Specifically, Xcel stated that it added Grand Meadow and Nobles to comply with the Renewable Energy Standard,[70] not to cost-effectively meet energy or capacity needs. By contrast, Pleasant Valley and Border Winds were acquired to minimize system costs, consistent with how other fixed production plant is added to the system.

XLI and the Chamber supported Xcel's approach to classifying Grand Meadow and Nobles. Alternatively, the Chamber advocated that the Nobles and Grand Meadow costs be classified using the "percent of base revenue" method.

The Department opposed Xcel's change in treatment of Nobles and Grand Meadow costs and recommended that the Company continue to classify all its proprietary wind generation using the plant-stratification method. The Department argued that it was inappropriate to classify wind facilities as 100% capacity-related, since such facilities can only generate electricity when the wind blows and thus cannot be counted upon to provide capacity at times of peak demand.

The OAG also disagreed with Xcel's proposed classification of Grand Meadow and Nobles as 100% capacity-related. It recommended that the Company instead classify the costs of those facilities as 100% energy-related. In support of its position, the OAG noted that the Renewable Energy Standard measures compliance in terms of "total retail electric sales" (i.e., energy) and not in terms of installed capacity. The OAG, however, stated that it would also support continued use of the plant-stratification method for these wind facilities.

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that Xcel had not demonstrated that the Grand Meadow and Nobles facilities should be classified as 100% capacity-related. She reasoned that the fact that these facilities were built to satisfy a legislative mandate does not change their operational characteristics and therefore does not provide a basis for classifying them as 100% capacity-related. For similar reasons, the ALJ rejected the OAG's recommendation to classify Grand Meadow and Nobles as 100% energy-related.

The ALJ recommended that the Commission require Xcel to modify its 2014 and 2015 class-cost-of-service studies to classify the costs of Grand Meadow and Nobles on the same basis as its other fixed production-plant costs.

4. Commission Action

The Commission concurs with the Administrative Law Judge and adopts her findings and recommendation.

The Commission finds that the plant-stratification method is appropriate for classifying and allocating Xcel's production plant, including the costs of wind facilities acquired to satisfy the Renewable Energy Standard. State policy undoubtedly encourages the development of renewable

[70] Minn. Stat. § 216B.1691.

resources as part of electric utilities' generation portfolios. However, it does not necessarily follow that those resources are not least-cost. Nor does that appear to be the case here, since Xcel has acknowledged that Nobles and Grand Meadow were economical when acquired.

Moreover, regardless of why a wind farm is added to the Company's system, the fact remains that such a resource produces little capacity. The plant-stratification method results in a cost allocation that closely matches this reality. Thus, that method continues to be the most reasonable alternative for classifying the fixed costs of wind generation. The Commission will therefore require Xcel to modify its 2014 and 2015 class-cost-of-service studies to classify the costs of the Grand Meadow and Nobles wind farms using the plant-stratification method.

D. D10S Capacity Allocator

1. Introduction

Once fixed production-plant costs are split into capacity and energy subfunctions, those costs must then be allocated to the different customer classes. In its class-cost-of-service studies, Xcel allocated capacity-related costs to the various customer classes based on each class's contribution to the Company's summer peak demand. Xcel's summer-peak-based allocator is called the D10S Capacity Allocator.

To ensure reliability when one or more plants fail, Xcel must have extra generation available to provide a capacity cushion above the level needed to meet peak demand. This cushion is known as a "planning reserve margin" and is set by the Midcontinent Independent System Operator, Inc. (MISO), which operates the Midwestern transmission system. MISO requires that a utility's planning reserve margin be set based on the utility's load at the time of MISO's system peak, which is in the summer.

Xcel believes its D10S summer-peak-based allocator is consistent with cost causation because it reflects the fact that the Company must plan for MISO's summer peak.

2. Positions of the Parties

The OAG argued that Xcel's method of demand allocation does not align with cost causation because the Company's system peaks on a different day and at a different time of day than MISO's system. In other words, the D10S allocator does not reflect each customer class's contribution to Xcel's system load at the time of the peak for which the Company must plan—MISO's. The OAG recommended that Xcel be required to calculate its D10S allocator using each class's demand that coincides with MISO's peak, rather than the Company's peak.

Xcel agreed that aligning the D10S allocator with MISO's peak would accurately reflect cost causation. However, the Company stated that it cannot calculate its capacity allocator using MISO's peak because MISO does not produce a forecast of its hourly loads for a test year.

The OAG recommended that the Commission require Xcel to collect the data necessary to perform the allocation. However, the OAG's witness acknowledged that he was "unaware of the data that is currently available or could be acquired in the future" to support the calculation.

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that, while the OAG had raised a noteworthy issue, it had not developed a sufficient record in this case to support its recommendation.

4. Commission Action

The Commission concurs with the ALJ that the record in this case does not contain the data needed to calculate a capacity allocator based on MISO's system peak, and it adopts her conclusion to that effect.

However, the Commission also agrees that the OAG has raised an important issue. Calculating a capacity allocator based on each customer class's contribution to Xcel's system load coincident with MISO's system peak would better reflect each class's share of the costs of meeting MISO's planning reserve margin. For the Company's next rate case, the Commission encourages Xcel to work with MISO and other parties to recalculate the D10S Capacity Allocator on the basis of MISO's peak for purposes of comparison with Xcel's peak.

E. Classifying Other Production Operation and Maintenance (O&M) Costs

1. Introduction

An electric utility incurs certain costs in operating a power plant for items other than fuel, such as labor, chemicals, information technology, maintenance, and licensing. These costs are referred to as "other production O&M costs." In this case, as in past rate cases, parties disagreed about the best method for classifying these costs as capacity- or energy-related.

Three different classification methods are relevant to this issue: (1) the overall-investment method, (2) the location method, and (3) the predominant-nature method.

Under the overall-investment method, other production O&M costs are classified as capacity- or energy-related in the same proportions as the plant where they were incurred.

Xcel used the overall-investment method in its last rate case. In that case, the Commission approved Xcel's use of the overall-investment method but required the Company to refine the method in its next rate case. Xcel calls this refined analysis the "location method."

Under the location method, other O&M costs are first reviewed to identify any costs that vary directly with the amount of energy produced. These costs are classified as energy-related and are allocated to the various customer classes using appropriate energy allocators. The remainder of the other production O&M costs are classified as capacity- or energy-related in the same proportion as the plant where they were incurred.

Xcel did not use the location method in its class-cost-of-service studies in this case. Instead, the Company used a method it called the "predominant nature method."

The predominant-nature method is similar to the first step of the location method. However, the predominant-nature method extends the analysis by classifying *all* nonfuel production O&M costs according to their "predominant" nature. If a particular item is determined to be predominantly a fixed expense, its cost is allocated to capacity; if an item is predominantly a variable expense, it is allocated to energy.

The table below shows the allocations that result when each method is applied to Xcel's other production O&M costs:

Method	Capacity Related	Energy Related
Overall investment	25.0%	75.0%
Location	35.0%	65.0%
Predominant nature	78.4%	21.6%

2. Positions of the Parties

The Chamber and XLI supported the Company's use of the predominant-nature method. These parties characterized the predominant-nature method as both more refined and more commonly used than the other methods.

The Department and the OAG, however, recommended that Xcel use the location method instead of the predominant-nature method in its class-cost-of-service studies. These parties argued that Xcel's use of the predominant-nature method was inconsistent with the Commission's order in the last rate case, which required the Company to use the location method. They also cited the Commission's and the Company's past preference for the overall-investment method rather than using a strict fixed/variable distinction to assign costs to demand and energy.

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that Xcel did not show that classifying other production O&M costs based on their predominant nature moves the resulting allocation closer to cost. She found that the location method was the most reasonable method in the record of classifying other production O&M costs and recommended that the Commission require the Company to modify its class-cost-of-service studies to use this method.

4. Commission Action

The Commission concurs with the ALJ and adopts her findings and recommendation.

Classifying as energy-related any costs that vary directly with the amount of energy produced at a plant, as the Commission has ordered Xcel to do, clearly moves the resulting allocation closer to cost. However, it is not evident that classifying each O&M category as energy- or capacity-related based on whether the category is predominantly variable or fixed results in an accurate energy/capacity allocation.

A number of O&M expenses do not fit neatly into this binary distinction between fixed and variable costs. For example, Xcel classified both employee and contract labor as fixed costs and allocated them to capacity. However, labor costs are likely to increase somewhat as a plant's energy production increases and decrease somewhat when production decreases.

Moreover, the predominant-nature method fails to account for the fact that Xcel builds baseload plants to meet both demand and energy needs. The location method appropriately accounts for this fact by allocating nonfuel O&M costs, other than those that vary directly with the amount of energy produced, to the capacity and energy subfunctions based on the underlying allocation of fixed plant costs.

For the foregoing reasons, the Commission will require Xcel to modify its 2014 and 2015 class-cost-of-service studies to use the location method to allocate other production O&M costs. Further, in its next rate case, the Company should continue using the location method to allocate these costs. It should also explain each allocation method used in its class-cost-of-service study, as more fully detailed in the ordering paragraphs.

F. Allocating Distribution Costs

1. Introduction

Xcel used the “minimum size” method, a type of minimum-system study, to separate the costs of its primary lines, secondary lines, secondary transformers, and service drops into customer-related and capacity-related components.

Under the minimum-size method, a utility compares the cost of the minimum size of each type of component used in its distribution system to the actual cost of the facilities installed. The cost of the minimum-size facilities is the customer-related component, and the capacity-related component is the difference between the total installed cost and the minimum-size cost.

The theory of minimum-system analysis is that any distribution system larger than the minimum required to allow a customer to receive service (the customer cost) has been installed to allow the utility to meet demand.

2. Positions of the Parties

The OAG argued that Xcel’s minimum-size analysis likely overstates the customer-related costs of its distribution system. The OAG pointed out several methodological flaws in Xcel’s study, including a lack of clear criteria for what constitutes “minimum sized” equipment and outdated cost data for the Company’s distribution components. Moreover, the OAG argued that a zero-intercept study, which uses regression analysis to estimate the cost of a hypothetical no-load distribution system, would yield a more accurate allocation of customer- and capacity-related distribution costs.

The OAG recommended that Xcel be required to conduct a zero-intercept analysis in its next rate case and to provide sufficient data for a minimum-size analysis. Also, based on its view that the Company’s study overstated customer costs, the OAG recommended that Xcel be required to allocate 10% more distribution costs as capacity costs and 10% less as customer costs in this case.

Xcel defended the accuracy of its minimum-size study and argued that the OAG’s proposed 10% adjustment is based on one minimum-size component whose cost was overstated but ignores other components whose cost was understated. Xcel stated that it did not object to the OAG’s recommendation to conduct a zero-intercept analysis in the next rate case, provided that the Company is able to compile the detailed property records necessary for the analysis.

3. The Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission require Xcel to file a zero-intercept analysis of distribution costs in its next rate case, as well as a minimum-size analysis. The ALJ concluded that requiring the Company to improve its minimum-system analysis in the next rate case was preferable to adjusting distribution costs by 10% in this case.

4. Commission Action

The Commission concurs with the Administrative Law Judge and adopts her findings and recommendation.

The OAG has raised valid concerns regarding the value of the data Xcel used to support its minimum-system study. The Company last estimated the average cost of its minimum distribution equipment in 1991 and has since simply adjusted this cost yearly for inflation. Moreover, the minimum-size method may produce a larger customer-cost allocation than the more rigorous zero-intercept analysis. A zero-intercept analysis will serve as a valuable cross-check of Xcel's minimum-size analysis.

For the foregoing reasons, the Commission will require Xcel, in its next rate case, to provide the parties with data sufficient to verify and reproduce its minimum-system study and to file a zero-intercept analysis of distribution costs, or explain why it was not able to collect the data necessary to do so.

RATE DESIGN ISSUES

XXIX. Implementation of a Decoupling Mechanism: Introduction

A. Xcel's proposal

Xcel asked the Commission to authorize a three-year pilot program implementing a revenue decoupling mechanism (RDM) for three customer groups: residential customers with electric space heating,[71] residential customers without electric space heating,[72] and small business customers who do not pay a demand charge.[73] This would make Xcel the first electric utility in Minnesota to adopt a revenue decoupling mechanism.

Under Xcel's proposal, the Company would calculate each customer group's revenue requirement excluding fuel-related revenues and fixed customer charges, divided by the number of customers in the group. At the end of each calendar year, Xcel would compare this per-customer revenue requirement to the average revenues it derived per customer within each group (adjusted to reflect normal weather patterns), and adjust rates in the following year to true-up the difference.

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[71] This would include customers served on rate codes A00, A01, A02, A03, A04, A05, and A06.

[72] This would include customers served on rate codes A01, A02, A03, A04, A05, and A06.

[73] This would include customers served on rate codes A05, A06 1S, A06 3S, A06 P, A09, A10, A11, A12, A16, A18, and A22.

Xcel proposed two limitations on any upward rate adjustment. First, in any year in which Xcel failed to achieve 1.2% in energy savings, the Company would forgo the opportunity to increase rates in the following year. Second, Xcel would adopt a 5% "soft cap" on any rate increase; any sums excluded from recovery by the cap would be deferred for recovery in the following year's adjustment. If the Commission were to modify Xcel's proposal to eliminate the weather adjustments, Xcel would propose increasing the soft cap to 10%.

B. Summary of Commission Action

In summary, the Commission will approve Xcel's proposal with modifications. In reaching this conclusion, the Commission makes the following findings.

First, Xcel has justified implementing a revenue decoupling mechanism for the customer groups in question, at least on a trial basis, with the following additions.

- *Customer education*: Xcel must file a plan to implement an education and outreach program for its customers explaining the goals and operations of its RDM program.
- *Start of energy-consumption measurement*: Xcel may begin calculating its over- or under-recovery of costs after the final compliance order authorizing implementation of final rates in this proceeding, but not before new rates take effect, and no sooner than January 1, 2016.
- *Annual report*: In the annual report Xcel proposes to file regarding its experience with the RDM, Xcel must include descriptions of factors other than the RDM that might have contributed to any change in conservation levels.

Second, the Commission will direct Xcel to implement a full decoupling mechanism (omitting weather normalization) rather than a partial decoupling (adjusting data to compensate for abnormal weather).

Third, the Commission will direct Xcel to cap any upward rate adjustment to 3% of the customer group's revenues, excluding revenues from the fuel clause or other riders. Where the cap prevents Xcel from fully recovering its deferred costs, the Commission will permit the Company to petition to recover these costs via the following year's adjustment. However, Xcel must first demonstrate that its demand-side-management programs and other company initiatives were a substantial contributing factor to the declining energy sales triggering the rate adjustment, and that other nonconservation factors were not the primary factors for the declining sales.

Fourth, the Commission will decline ECC's proposal to calculate adjustments based on average customer revenues including customer charges. Rather, the Commission will approve Xcel's proposal to exclude customer charges from the adjustment calculation.

These decisions will be discussed more fully below.

XXX. Implementation of a Decoupling Mechanism: General Objections

A. Introduction

Before addressing concerns about specific provisions in Xcel's revenue decoupling proposal, some parties stated an opposition to revenue decoupling in general.

B. Positions of the Parties

Decoupling was opposed on principle by AARP, the ICI Group, and the OAG. In contrast, decoupling was defended in principle by the Clean Energy Intervenors (CEI), the Department, ECC, and Xcel.

For example, AARP argued that decoupling would reduce a customer's incentive to conserve because reductions in sales today would trigger upward rate adjustments in the future. Xcel argued that these concerns were overstated: A customer who conserves a kilowatt-hour (kWh) reduces his bill by the price of one kWh immediately. The rate adjustment triggered by the customer's actions would be spread throughout the customer's class, and over 12 months. As an incentive to conserve, the magnitude and immediacy of reducing a bill would overwhelm the small, attenuated rate adjustment arising roughly a year later.

AARP and the OAG challenged Xcel's choice to propose its RDM only for its smallest customers, not for Xcel's large industrial customers that consume most of the Company's energy. Xcel explained that each kWh charged to a residential or small business customer contains a higher percentage of fixed (nonfuel) costs than a kWh charged to a large commercial and industrial customer, and the rate adjustments are designed to recover these costs. Xcel argued that it makes sense to initiate a pilot RDM program where the program could have the largest effect per kWh.

On the other hand, the ICI Group objected that Xcel's proposal fails to give enough emphasis to the distinctions among customer groups. The ICI Group asks the Commission to remedy this oversight by ruling that Xcel must never seek to apply a revenue decoupling mechanism to large commercial and industrial customers.

AARP and the OAG argued that revenue decoupling would impose disproportionate burdens on customers who consume the least energy. But Xcel analyzed how its RDM would affect customers in a variety of circumstances, and demonstrated that even customers with relatively low usage could be held harmless, or even benefit, from this rate design.[74]

AARP, the ICI Group, and the OAG argued that decoupling would not increase Xcel's implementation of conservation programs because the Company already has sufficient mandates and incentives to implement conservation programs. They objected that Xcel never proposed to track whether any additional savings would in fact result from its RDM. In response, Xcel argued that the Legislature has not treated conservation/efficiency programs and revenue decoupling as substitutes, but as complements.

Finally, AARP and the OAG argued that decoupling is complicated and will confuse customers. They claimed that Xcel has not developed a strategy for educating customers about this new rate design, or for managing the resulting confusion.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that it is reasonable for the Commission to implement revenue decoupling in this rate case. The ALJ found that revenue decoupling can remove a utility's disincentives to

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[74] Ex. 111 (Hansen Surrebuttal) at 7–11.

promote energy efficiency and conservation without adversely affecting ratepayers. Moreover, while Xcel has been meeting its energy efficiency goals, the ALJ found that the Company had persuasively argued that meeting these goals would become more difficult in the future. Finally, the ALJ concluded that the record did not support a conclusion that decoupling would inevitably cause customer confusion.

Xcel expressly supported the ALJ's decoupling recommendation. CEI and the Department supported the ALJ's Report generally. In contrast, AARP, the ICI Group, and the OAG each opposed the ALJ's recommendation for the reasons previously stated.

D. Commission Action

1. Support for Revenue Decoupling

The Commission concurs with the ALJ that revenue decoupling has substantial potential to align the Company's interests with the public's interest in conservation and energy efficiency.

Based on the evidence in the record, the Commission finds insufficient support for the proposition that revenue decoupling would create systemic disadvantages for any customer group, or any specific type of customer. Ultimately Xcel's proposed mechanism is well designed to enable Xcel to recover its revenue requirement—no more and no less. Xcel will benefit from this type of assurance, and so will ratepayers.

Additionally, the Commission concludes that Xcel has articulated a reasoned basis to initially limit its proposed revenue decoupling mechanism to its residential and small business customers. That said, the Commission will decline the ICI Group's request to declare that Xcel may never implement revenue decoupling for its large energy group; as a general practice the Commission refrains from offering advisory opinions on proposals not yet submitted.

While the objecting parties have not persuaded the Commission to reject revenue decoupling, they have identified room for improvement in Xcel's proposal.

2. Reporting

Xcel stated that it proposed its RDM to remove disincentives for the promotion of conservation and energy efficiency, but AARP and the OAG objected to Xcel's failure to propose measuring the additional conservation that would result from the RDM.

The change in the amount of the electricity consumed can be measured directly; in contrast, whether revenue decoupling *caused* the change can only be inferred. This inference requires consideration of all other potential causes and an examination of the relevant data.

In establishing criteria for revenue decoupling proposals, the Commission directed each utility implementing an RDM to report data on its experiences annually.[75] Consistent with this requirement, Xcel has agreed to make an annual report including the following information:

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[75] *In the Matter of a Commission Investigation into the Establishment of Criteria and Standards for the Decoupling of Energy Sales from Revenues*, Docket No. E,G-999/CI-08-132, Order Establishing Criteria and Standards to be Utilized in Pilot Proposals for Revenue Decoupling at 8–9 (June 19, 2009).

1) Total over- or under-collection of allowed revenues by customer class or group.

2) Total collection of prior deferred revenue.

3) Calculations of the RDM deferral amounts.

4) The number of customer complaints.

5) The amount of revenues stabilized and how the stabilization impacted Xcel's overall risk profile.

6) A comparison of how revenues under traditional regulation would have differed from those collected under partial and full decoupling.[76]

The Commission finds this reporting proposal reasonable and will accept it.

But in addition, an analysis of the effectiveness of Xcel's RDM would be aided by information about other circumstances that might have caused sales to the relevant customer groups to differ from forecasted sales. To this end, the Commission will direct Xcel to include the following supplementary information in its annual report:

7) A description of all new and existing demand-side-management programs and other conservation initiatives Xcel had in effect for the year covered by the report.

8) A description of the effectiveness of all new and existing demand-side-management programs and other conservation initiatives Xcel had in effect for the year covered by the report.

9) Other factors that may have contributed to a decline in energy consumption, including weather and the economy.

Under the RDM, Xcel will gather data on customer sales through the end of the calendar year, then calculate rate adjustments to take effect by April 1 of the following year. The Commission will direct Xcel to file its annual report by February 1, two months before the new rate adjustments take effect.

3. Customer Confusion

The Commission has considered the arguments that Xcel has not developed an adequate strategy for educating customers about this new rate design or for managing potential customer confusion. While the ALJ observes that there is little record evidence of revenue decoupling triggering customer confusion, the Commission finds that parties have raised reasonable concerns. Decoupling is a less familiar method of designing utility rates, and can be easily misunderstood.

To better address this issue, the Commission will direct Xcel to file a plan for implementing an education and outreach program for its customers. Xcel should design this program to convey to members of the relevant customer groups the goals and operations of its revenue decoupling

[76] Ex. 109 (Hansen Direct) at 18–19; Ex. 417 (Davis Direct) at 21.

program. With an appropriate education program, Xcel will be able to address customer questions as they arise, and help customers understand the new rate design's advantages.

Finally, the Commission will add clarity to Xcel's proposal by establishing a start date.

One of Xcel's first steps in implementing revenue decoupling is measuring a baseline customer consumption level to determine how much actual sales differ from forecasted sales. Consumption can vary for many reasons, including price. Xcel will set new rates through the current proceeding, but those rates have not taken effect yet. It would make sense to delay the collection of sales data until the new rates are implemented.

For purposes of calculating the first RDM adjustment, therefore, the Commission will authorize Xcel to begin collecting data on sales that occur after the Commission issues its final compliance order in this docket and the new rates take effect, but in no event sooner than January 1, 2016.

XXXI. Design of Revenue Decoupling Mechanism: Weather-Related Risk

A. Introduction

The weather influences the amount of energy an electric utility sells: all else being equal, hotter temperatures tend to increase energy sales while cooler temperatures tend to reduce them.

Under traditional rate design, utilities and customers bear this weather-related financial risk. But a revenue decoupling mechanism can be designed to permit all parties to mitigate this risk. That is, it can enable a utility to recover a customer group's nonfuel costs, and limit customer payment of nonfuel costs, to the levels found to be just and reasonable in a rate case regardless of the weather (so-called "full decoupling"). Or the mechanism can be designed to leave the weather-related financial risks with the parties ("partial decoupling").

Parties disagree about whether the Commission should authorize Xcel to pursue full or partial decoupling.

B. Positions of the Parties

1. Partial Decoupling

Xcel proposed a partial decoupling mechanism. The Company justified its proposed decoupling mechanism as a means of removing its disincentives to pursue conservation; avoiding weather-related risks was not part of Xcel's rationale. Also, having limited experience with decoupling, Xcel favors incremental steps—and incrementalism favors leaving weather-related risk with the utility, as occurs with traditional rate design.

2. Full Decoupling

The Department favored full decoupling on the theory that it could lead to cost reductions under some scenarios and that, when combined with Xcel's other incentives to promote conservation and efficiency, decoupling would improve the regulatory environment for promoting conservation. The Department argued that Xcel's proposed pilot program would provide an appropriate opportunity to explore a full-decoupling rate design.

The Department analyzed how full and partial decoupling would have influenced the size of customer bills for the residential and small business customer groups for a ten-year period relative to Xcel's actual rates. The Department's analysis showed that full decoupling would have increased customer bills less than partial decoupling. But the Department acknowledged that these results were influenced by the fact that Xcel experienced warmer-than-average weather during 2009-2013, and potentially by the economic recession.

While the OAG opposed decoupling overall, it favored full decoupling over partial decoupling. In an environment in which current weather may tend to be hotter than the 20-year historical average, the OAG argued that efforts to adjust electric rates for "normal weather" may contain a systematic bias for higher rates.

3. Either Full or Partial Decoupling

CEI stated that it could support either full or partial decoupling.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission approve a full decoupling mechanism, adjusting Xcel's rates to provide recovery of nonfuel costs from the relevant customer groups regardless of weather. The ALJ noted that either rate design would reduce Xcel's disincentive to promote conservation and efficiency. But the ALJ cited the Department's analysis for the proposition that customers could expect lower rates under a full decoupling regime than under a partial regime, and that partial decoupling could result in customers being overcharged.

Xcel disputed the statement that rate adjustments under partial decoupling could result in customers being overcharged. Xcel acknowledged that during periods of abnormally hot weather, partial decoupling would result in higher customer bills than full decoupling and potentially higher than traditional rates. But Xcel argued that this result would be driven by the unusual weather, not by any error in the rate design. Xcel reanalyzed the Department's study while making adjustments to reflect different weather patterns, and concluded that partial decoupling might produce bills that are higher or lower than bills under full decoupling depending on whether temperatures prove to be higher or lower than normal.

D. Commission Action

The Commission concurs in the Administrative Law Judge's recommendation to authorize the use of a full decoupling mechanism.

Xcel offered two arguments in support of partial decoupling. First, the Company argued that partial revenue decoupling tracks more closely the risk allocation of traditional rate design. But it is unclear that this risk allocation was ever a goal of traditional rate design, rather than simply an incidental result.

Second, Xcel argued that mitigating weather risk was simply irrelevant to the goal of removing disincentives for conservation and efficiency. Yet full revenue decoupling can accomplish both results, and the pursuit of either goal does not compromise the other. CEI's witness, while supporting Xcel's partial-decoupling proposal in this proceeding, acknowledged testifying in support of full decoupling in other proceedings.[77] Indeed, full revenue decoupling is simpler and more transparent than partial decoupling because the annual rate adjustments can be calculated without the need for complicated weather-normalization adjustments.

The OAG argued for one additional benefit of full decoupling: According to the OAG, the average weather conditions over the past 20 years no longer provide a reliable estimate of future weather due to long-term warming trends. If so, then a rate design that depends heavily on estimates of normal weather—including traditional and partially decoupled rate designs—would tend to underestimate the amount of electric energy consumers will demand, resulting in inappropriately high rates. Full decoupling would compensate for any such bias by adjusting future rates to reflect sales that differ from the forecast.

On the other hand, if the OAG's concerns prove to be unwarranted and sales forecasts prove to be accurate or high, revenue decoupling would appropriately adapt to that scenario as well. In other words, full revenue decoupling would provide a means of compensating for inaccuracies in the sales forecast—regardless of the source of the inaccuracies—without adding financial burdens to ratepayers if the sales forecast proves to be accurate.

Because full revenue decoupling is simpler, more transparent, and potentially more beneficial than partial decoupling, the Commission will authorize Xcel to implement a full revenue decoupling rate design for its residential and small business customers.

XXXII. Design of Revenue Decoupling Mechanism: Cap on Potential Rate Increase

A. Introduction

As previously discussed, a decoupling mechanism works by calculating the amount of nonfuel costs a utility has recovered through rates, comparing that sum to the amount the Commission authorized the utility to recover, and adjusting future rates to offset any over- or under-recovery over time.

To guard against the possibility that unforeseen circumstances might cause the adjustment formula to authorize inordinately large rate increases, all parties propose capping the size of the potential increase in any given year. But questions remain about the details of a cap. In particular, when a cap would exclude Xcel from recovering its full amount of nonfuel costs in a given year, should the Company have the opportunity to recover the excess via the following year's adjustment (a "soft cap") or not (a "hard cap")?

B. Positions of the Parties

1. Soft Cap

CEI and Xcel favored a soft cap. That is, whenever the amount of costs to be recovered in any year would cause the adjustment to exceed the capped level, Xcel would increase rates up to the level of the cap and would defer recovery of the remainder to the following year. Xcel argued that a cap provides ratepayers with assurance that the revenue decoupling mechanism could not produce rate swings large enough to provoke rate shock.

[77] Ex. 294 (Cavanagh Rebuttal) at 6.

But a hard cap, CEI and Xcel argued, would undermine the goals of decoupling: It would leave a utility at risk of being unable to fully recover its nonfuel costs if it sells less energy than forecast, thus discouraging the utility from promoting conservation and efficiency. In its review of 25 electric decoupling mechanisms adopted in other states, Xcel found only two that used a hard cap—and most had no cap at all.

If the Commission were to authorize full revenue decoupling, Xcel would propose limiting the size of any upward rate adjustment to no more than 10% of the customer group's revenues, excluding revenues for energy and other riders. If the Commission were to authorize partial revenue decoupling, Xcel would propose a 5% cap. Xcel argues that full decoupling—designed to address fluctuations in the weather as well as other variables—would warrant a larger cap than partial decoupling.

ECI also favored setting a cap as a percentage of a customer group's revenues excluding revenues from riders, but did not advocate a specific cap size.

2. Hard Cap

AARP, the Department, and the OAG favored a hard cap whereby Xcel would forgo recovery of any sums excluded from recovery by the adjustment cap. They noted that the Commission had approved hard caps for other utilities' revenue decoupling mechanism.[78] In contrast, they opposed Xcel's soft-cap proposal. They argued that a soft cap would fail to protect ratepayers from unforeseen circumstances triggering an inordinately large rate adjustment; it would merely spread the cost recovery over a longer period.

AARP, the Department, and the OAG opposed any proposal to set a cap greater than 3% of a customer group's revenues. In particular, they disputed Xcel's claim that full revenue decoupling would warrant a 10% cap. The Department's analysis showed that, if Xcel's standard residential group had operated with full revenue decoupling over the past ten years, the highest adjustment would have been less than 3%.

That said, each of these commenters offered its own rate-cap recommendation.

The Department recommended that the Commission limit any rate increase arising from the RDM to no more than 3% of the customer group's revenues, although the Department recommended that these revenues incorporate adjustments from the fuel clause and other riders. The Department estimated that this cap would limit the size of any decoupling-related rate adjustment to $27 per year for residential customers, and $35 per year for residential customers with electric space heating.

[78] *See In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G-007,011/GR-10-977, Findings of Fact, Conclusions, and Order (September 12, 2012); *In the Matter of an Application by CenterPoint Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-13-316, Findings of Fact, Conclusions, and Order (June 9, 2014).

The Department stated that a cap below 3% might provide more protection to ratepayers, but at the utility's expense. The Department argued that a 3% cap reflects a reasonable compromise among competing considerations.

AARP favored setting the hard cap at 2% of customer group revenues, excluding revenues from riders such as the fuel clause.

Finally, the OAG supported capping Xcel's decoupling adjustments at 1% of a customer group's revenues.

C. The Recommendation of the Administrative Law Judge

The ALJ found that the record did not demonstrate that Xcel's soft-cap proposal would appropriately shield ratepayers from unanticipated rate increases that might arise from an unfamiliar rate design. In addition, the ALJ found that the record did not demonstrate the need for a cap of more than 3%. Consequently the ALJ recommended that the Commission modify Xcel's proposed revenue decoupling mechanism as proposed by the Department—that is, to include a 3% hard cap on all revenues, including fuel and applicable riders.

AARP, the OAG, and Xcel each took exception to the ALJ's recommendations, generally reasserting their earlier positions.

D. Commission Action

The Commission concurs with the ALJ and all parties that it would be beneficial to establish a cap on rate increases triggered by the RDM, especially given the Commission's lack of familiarity with applying decoupling to electric utilities. But the parties disagree about whether to select a hard or soft cap, and the appropriate magnitude of the cap.

1. Hard Cap vs. Soft Cap

Both a hard cap and a soft cap could achieve the goal of limiting the RDM's capacity to adjust rates upward in any given year.

Relative to a soft cap, a hard cap would be simpler to explain and administer, and would be expected to result in somewhat lower rates over time.

But because a hard cap would function as a limit on an RDM, it would also limit Xcel's ability to achieve the advantages that a RDM has over traditional rate design. That is, a hard cap would again give Xcel some incentive to promote energy sales, conflicting with state policy and incentives promoting conservation and efficiency. And a hard cap would again put Xcel at risk of losing the opportunity to recover Commission-approved costs for reasons beyond the Company's control, such as unusually cold weather.

Given these competing considerations, the Commission will pursue a middle path. Consistent with a soft cap, the Commission will provide Xcel with the opportunity to recoup costs that the Company was unable to recover during the previous year due to the cap on RDM rate increases. Yet this cost recovery will not be automatic; rather, Xcel will have to petition the Commission for authority to recover these costs. In the petition, Xcel would have to demonstrate that its demand-side-management programs and initiatives were a substantial contributing factor to the declining energy sales that triggered the rate adjustment, and that its declining sales were not driven primarily by factors unrelated to conservation and efficiency.

This modified cap will mitigate some of the adverse consequences of a hard cap while providing assurance that large rate adjustments are in fact tied to the purposes for which the RDM was proposed: the promotion of conservation and efficiency.

2. Magnitude of Cap

The Commission must now establish the magnitude of the cap. Parties have proposed levels ranging from 1% to 10%. Additionally, parties have disagreed about whether the percentage should be applied to all of a customer group's revenues, or should exclude revenues coming from riders such as the fuel clause.

Here, the Commission concurs with the ALJ and the Department that the record does not demonstrate a need for a cap exceeding 3%. The Department's analysis shows that setting the cap above 3% would virtually eliminate the cap for the standard residential customer because RDM rate increases would rarely exceed that level.

But the Commission disagrees with the ALJ and the Department about the merits of calculating the cap on the basis of all of a customer group's revenues, including revenues from riders. Part of the value of a cap is the assurance it provides ratepayers about the potential consequences of this new rate design. Because the magnitude of revenues from the fuel clause and other riders is prone to large fluctuations, the magnitude of a cap calculated on this basis becomes more speculative—that is, it would no longer provide ratepayers with reassurance. The Commission prefers a cap formula that provides a greater degree of clarity.

In summary, the Commission will cap the amount by which the RDM may increase a customer group's rates at 3% of the group's revenues, excluding revenues from the fuel clause and other riders. If the cap precludes Xcel from fully recovering its nonfuel costs through the RDM adjustment, the Commission may authorize Xcel to recoup the unrecovered balance through the following year's RDM adjustment. But Xcel must first demonstrate that its conservation efforts were a primary factor in reducing its energy sales, and hence its under-recovery of nonfuel costs.

XXXIII. Design of Revenue Decoupling Mechanism: Measurement of Adjustment

A. Introduction

As previously discussed, a decoupling mechanism works by calculating the amount of nonfuel costs a utility has recovered through rates, comparing that sum to the amount the Commission authorized the utility to recover, and adjusting future rates to offset any over- or under-recovery over time.

But even when parties agreed about the amount of over- or under-recovery to be recouped, and about the sales forecast, parties disagree about how to calculate the appropriate adjustment.

B. Positions of the Parties

Xcel proposed calculating the RDM adjustment by dividing the amount to be recovered or refunded within a given customer group by the forecast of kWh sales for that group. Xcel's formula takes no account of the fixed monthly customer charge paid by residential and small business customers. Xcel reasoned that this charge does not vary with the number of kWh a customer consumes, so it is already "decoupled" and should not influence the adjustment calculation.

The ECC advocated calculating the adjustment by dividing the amount to be recovered or refunded by the customer group's total revenues—that is, per-kWh charges plus customer charges. The ECC argued that calculating adjustments in this matter would avoid adding needless burdens to households with relatively low rates of energy consumption.

While AARP did not take a specific position on this matter, it advocated calculating the adjustment in whatever manner would provide the greatest relief to customers who consume the least amount of energy.

C. The Recommendation of the Administrative Law Judge

The ALJ found that ECC's proposal was not well supported in the record—and that among the advantages of Xcel's adjustment formula, it would allocate less of the adjustment to low-usage customers than ECC's proposal. Consequently the ALJ did not recommend altering Xcel's adjustment formula in the manner proposed by ECC.

D. Commission Action

The Commission concurs in the ALJ's findings, conclusions, and recommendations, and will adopt them.

If a party wanted to allocate the RDM rate adjustments in a manner that would minimize the consequences for customers with low energy usage, the simplest strategy would be to allocate the adjustment based on energy usage—just as Xcel proposed. Indeed, a hypothetical customer who used no electricity in a given month would be completely unaffected by the RDM rate adjustment for that month.

But even a customer who used no energy would pay a monthly customer charge. Thus, if Xcel were to calculate the RDM adjustment based on total group revenues—including revenues from customer charges—then even a customer with no energy usage would bear a share of the RDM adjustment.

Because the record does not demonstrate that ECC's proposal would achieve ECC's objectives, the Commission will decline to adopt it.

XXXIV. Class Revenue Apportionment

A. Introduction

In every rate case the new revenue requirement must be apportioned among the customer classes. This raises the issue of interclass revenue responsibility built into the rate structure—what portion of the revenue requirement should be recovered from each class? In this case, eight parties (the Company, the Department, the Chamber, XLI, the Commercial Group, the OAG, the Suburban Rate Authority, and AARP) proposed at least four different class revenue apportionments.

The parties disputed the significance of the class-cost-of-service studies (CCOSS) in establishing class revenue apportionment. Most parties agreed that rates should be moved closer to cost of service identified by a CCOSS. They disagreed about how closely the apportionment should match the CCOSS. The OAG supported an apportionment method that relies primarily on the apportionment approved in the Company's last rate case.

Adding to the complexity of the apportionment issue, the parties did not agree on how to adjust the class revenue apportionment if circumstances warranted changes to the company's revenue requirement or CCOSS. In prior rate cases, the Commission has applied a formula to adjust the apportionment proportionally, or has required the company to rerun its CCOSS with updated figures. Both methods were suggested as possibilities in this case.

B. Positions of the Parties

1. The Company

Xcel recommended an apportionment based on its CCOSS as a starting point, with modifications for noncost factors such as mitigating rate shock and ability to pay. It proposed an apportionment and stated that its proposal was based on the following parameters:

- Move the Residential class 75% closer to cost, as measured by the Company's proposed CCOSS;
- Set the Commercial and Industrial (C&I) Non-Demand class apportionment at the cost-based level, as measured by the Company's proposed CCOSS;
- Maintain the current level of Lighting class revenues; and
- Recover the remaining revenue requirement from the C&I Demand class.

The Company recommended that adjustments to apportionment in response to Commission revenue- or CCOSS-related decisions should be made using an adjustment formula.

2. The Department

The Department based its proposed apportionment on its own CCOSS. The Department recommended additional non-cost-based adjustments to reduce the magnitude of increases for certain classes.

Relative to the Company's proposal, the Department recommended that the Residential and Commercial and Industrial Non-Demand classes bear less of the rate increases in 2014 and 2015, and that the Commercial and Industrial Demand class bear more. The Department also recommended an increase for the Lighting class in 2015.

If Commission decisions on revenue requirement or CCOSS make adjustment necessary, the Department joined the Company's recommendation to adjust the class revenue apportionment using an adjustment formula.

3. The OAG

The OAG argued that after recommended adjustments are made, the CCOSS demonstrates that the residential and small business classes are paying more than the cost to serve them. The OAG proposed an apportionment based on the previous rate case's apportionment. The OAG argued that this approach (and its result) was warranted because class-cost-of-service studies are imprecise, and because it gives appropriate weight to relevant noncost factors.

The OAG recommended that revenues be apportioned according to the following general principles:

- Increase the revenues apportioned to the Residential and Commercial and Industrial Non-Demand classes by the Company's claimed deficiency percentage (6.91%);
- Maintain the current level of Lighting class revenues; and
- Recover the remaining revenue requirement from the Commercial and Industrial Demand class.

AARP supported the OAG's recommendation and advocated that customer classes should share equally in any overall rate increase.

4. The Chamber, the Commercial Group, and XLI

The Minnesota Chamber of Commerce, the Commercial Group, and the Xcel Large Industrials all recommended that the classes be apportioned revenue as close as possible to CCOSS class costs. They argued there was no noncost factor that justified departing from CCOSS-determined costs.[79] They also recommended that the CCOSS be rerun in the event of revenue or CCOSS changes.

5. The SRA

The Suburban Rate Authority opposed rate increases for the Lighting class, particularly the increases recommended by the Department in the 2015 Step. The SRA argued that the Company's CCOSS demonstrated that the Lighting class costs of service in 2014 and 2015 were below the rates charged to it.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission adopt the Department's proposed CCOSS methodology, with one modification. The ALJ recommended shifting the Department's proposed increase for the Lighting class in 2015 to the other classes, stating that the Department's recommendation would cause the Lighting class to pay above its cost in 2015. She also recommended adjusting the apportionment using the proportional-adjustment methodology supported by the Company and the Department.

[79] The Commercial Group did not oppose Xcel's proposal for a 75% movement to cost for the Residential class in the event that Commission decisions result in adjustments to the relative costs of the rate classes.

D. Commission Action

The Commission will adopt a slightly modified version of the apportionment method described by the Company. It will require Xcel to rerun the CCOSS in accordance with all Commission decisions in this docket that affect the CCOSS, and to set the class revenue apportionment by applying the following methodology to the revised CCOSS:

- Set the Commercial and Industrial Non-Demand class apportionment at the cost-based level indicated by the revised CCOSS;
- Move the Residential class 75% closer to cost—unless the revised CCOSS shows the Residential class is contributing more than its share of cost—in that case, set the Residential class apportionment at the cost-based level;
- Maintain the current level of Lighting class revenues; and
- Recover the remaining revenue requirement from the C&I Demand class.

The Commission believes this apportionment best balances the interests relevant to establishing just and reasonable rates. Apportioning revenues in accordance with class costs serves important principles by aligning revenue responsibility with cost causation, and thereby encouraging efficient use of resources. But it is appropriate to use CCOSS results as a starting point. Revenue apportionment affects rate-setting considerations beyond matching costs to causers, such as gradualism and ability to pay.

In this case, the Commission believes that the classes can reasonably be set at—or significantly closer to—their CCOSS-indicated cost. But, in the interest of protecting against rate shock from a possibly significant and sudden increase, any upward adjustment to the Residential class will be limited to 75% of the difference between that class's updated present revenue figure and its revised CCOSS-indicated cost.

Rather than apply a proportional-adjustment formula to determine class revenue apportionment, the Commission will require that the Company rerun its CCOSS with modifications required by this order, and calculate the apportionment based on that revised CCOSS. The Commission is not persuaded that in this case the formula adjustment recommended by the Company and the Department would produce a fair and reasonable result.[80]

XXXV. Method of Recovering CIP Costs

A. Introduction

Xcel and the Department agreed that when the final rates set in this case go into effect, the Company will stop recovering its Conservation Improvement Program (CIP) Costs through base

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[80] Xcel's proposed adjustment formula shifts relative revenue responsibility based in part on initial revenue estimates. Because the Company's revenue estimates have changed, applying the formula in this case could result in an unintended allocation. For example, it appears that the adjustment formula would shift revenue responsibility to the Residential and C&I Non-Demand class above the cost attributed to them in the Department's CCOSS. The result would be to recover tens of millions of additional dollars from Residential and C&I Non-Demand customers rather than C&I Demand customers (who would be responsible for an allocation below their CCOSS-estimated cost).

rates, subject to true-up through an automatic-adjustment mechanism or rate rider, and start recovering them entirely through the rider. They stated that this ratemaking treatment would be more efficient than continuing to recover CIP costs through base rates subject to true-up.

The Administrative Law Judge treated this as a settled issue and made no findings on it.[81]

The Commission will not accept the parties' resolution of this issue, but will require that CIP costs continue to be recovered through base rates, subject to true-up by rider, as explained below.

B. CIP Costs and Their Current Method of Recovery

CIP expenses are an integral part of the cost of service. The CIP program encompasses most of the State's energy-conservation and energy-efficiency initiatives, from energy audits and appliance rebates to energy-efficient construction guidelines and manufacturing process improvements.

CIP costs are recovered differently than most other test-year costs. Most utility costs are built into rates using the test-year concept—they are built in at amounts determined to be reasonable and prudent by examining all utility costs over the course of a representative one-year period, the test year. While actual costs going forward will differ from test-year costs to some extent in every category, the careful scrutiny these costs receive during a rate case is expected to ensure that these cost differences will be essentially symmetrical, favoring neither the Company nor ratepayers in the aggregate.

As a matter of public policy, the Legislature has determined that utilities should generally be permitted to recover their CIP costs dollar for dollar, instead of relying solely on test-year rate recovery. CIP costs are therefore recovered in two ways: through the Conservation Cost Recovery Charge (CCRC), a component of base rates that recovers baseline, test-year CIP costs, and through the Conservation Cost Recovery Adjustment (CCRA), an automatic rate-adjustment mechanism that trues up differences between actual CIP costs and those recorded in the CCRC.

In Xcel's case, the CCRA is part of a larger rider, or automatic rate-adjustment mechanism, the Resource Adjustment Charge, which includes the costs of other programs and investments mandated under State energy-policy statutes.

C. Commission Action

The Commission will not approve removing CIP costs from base rates and recovering them entirely by rider.

Riders are regulatory tools for use in essentially two situations: (1) when the delay implicit in normal test-year treatment of costs could defeat or frustrate important public-policy objectives, such as prompt construction of essential transmission or renewable-energy facilities,[82] and (2) when large costs, such as fuel costs, fluctuate so substantially that relying solely on base-rate recovery would necessitate nearly constant rate cases.[83]

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[81] ALJ's Report, Attachment A, "Resolved Issues and Undisputed Corrections," Issue 39.

[82] Minn. Stat. §§ 216B.16, subd. 7b, .1645, subd. 2.

[83] Minn. Stat. § 216B.16, subd. 7.

Riders are used with care because cost-recovery inquiries in rider proceedings are necessarily less thoroughgoing than those in general rate cases—potentially jeopardizing ratemaking accuracy—and because conducting cost-recovery inquiries in both rider proceedings and rate cases complicates ratemaking and reduces regulatory efficiency. That is why the Commission's Multiyear Rate Plan Order requires filing utilities to disclose, examine, rationalize, and simplify existing riders.[84]

The Commission continues to view reduced dependence on rate riders and their continuing simplification as important regulatory goals and will not authorize rate recovery of the Company's CIP costs through a rate rider alone.

Further, a rate-design change of this magnitude requires more thorough review than can be conducted in a rate case; it merits consideration in a separate proceeding with broad stakeholder participation. For all these reasons, the Company should continue to recover those costs in base rates, subject to true-up by rider.

XXXVI. Residential and Small-General-Service Customer Charges

A. Introduction

Xcel's Residential and Small General Service customers pay both an energy charge and a customer charge. The energy charge is a per-kWh charge based on electricity use. The customer charge is a fixed monthly charge assessed without regard to usage level. It is designed to help recover fixed customer-related costs such as the cost of billing, meters and meter reading, and the minimum distribution facilities required to provide service.

The Company's 2014 class-cost-of-service study estimated that the average fixed monthly cost of serving a residential customer is $15.86 and that the average fixed monthly cost of serving a small general-service customer is $16.84.

Xcel's current Residential and Small General Service customer charges are lower than the cost of service estimated in the Company's class-cost-of-service study. Xcel proposed to increase the Residential customer charge by $1.25 and the Small General Service customer charge by $1.50 to move them closer to cost and minimize intraclass subsidies.

Xcel's current and proposed customer charges for these classes are as follows:

Service	Current Charge	Proposed Charge
Residential Overhead	$8.00	$9.25
Residential Underground	$10.00	$11.25
Residential Electric-Heat Overhead	$10.00	$11.25
Residential Electric-Heat Underground	$12.00	$13.25
Small General Service	$10.00	$11.50

[84] Docket No. E,G-999/M-12-587, Multiyear Rate Plan Order at 7–8, 12, 14.

B. Positions of the Parties

The Department agreed with Xcel that the Residential and Small General Service customer charges should be increased. The Department shared the Company's concern that current rates result in intraclass subsidies. Because the current customer charges do not reflect the full fixed cost of service, it argued, some fixed costs are recovered through the energy charge, and high-usage customers end up paying more than their share of fixed costs. According to the Department, some of these high-usage customers are low-income customers with a limited ability to absorb a rate increase.

Although it agreed that the customer charges should be raised, the Department recommended a more modest increase of $0.50 per month. The Department noted that a customer-charge increase would follow closely on the previous increase in Xcel's last rate case, which was implemented in December 2013. The Department argued that an increase of $0.50 per month appropriately balances reducing intraclass subsidies and maintaining affordability.

The remaining parties commenting on this issue—the OAG, the Clean Energy Intervenors, the Energy CENTS Coalition (ECC), AARP, and the Suburban Rate Authority—all recommended leaving the customer charges at their current level.

These parties' arguments for retaining the current charges fell into the following broad categories: (1) the need to maintain affordability, (2) the need to encourage energy conservation, and (3) doubt as to whether Xcel's class-cost-of-service study accurately reflects the fixed cost of serving a customer.

As to affordability, several parties argued that an increase in the Residential customer charge would place an undue burden on low-usage residential customers. The OAG in particular was concerned about the cumulative impact of multiple increases to the Residential and Small General Service charges in recent years and argued that it was more important to protect ratepayers from the impact of frequent increases than to move the charges closer to cost.

Second, parties argued that retaining the current charges would further the rate-setting goal of encouraging energy conservation.[85] Holding the customer charges steady will shift the impact of any increase in these classes' revenue responsibility into the per-kWh energy charge, giving customers a greater ability to avoid the increase by using less electricity. Several parties argued that a decision to implement revenue decoupling would further support holding the customer charges steady, since decoupling would remove the risk of Xcel under-recovering its revenue requirement as a result of reduced energy sales.

Finally, the OAG and the Clean Energy Intervenors argued that Xcel's class-cost-of-service study is not a reliable measure of fixed customer costs because it classifies as customer-related significant costs that do not vary directly with the number of utility customers. The Clean Energy Intervenors argued that the actual fixed cost of serving a residential customer is less than $6.51 per month. Thus, according to them, low-usage Residential customers are currently paying more than their fixed cost of service.

[85] *See* Minn. Stat. § 216B.03.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that, in this case, the need to maintain affordability and promote conservation outweighed the need to move rates closer to Xcel's class-cost-of-service study's estimate of the fixed cost of service.

The ALJ was persuaded by the Clean Energy Intervenors' and the OAG's arguments that Xcel's class-cost-of-service study did not present a reliable estimate of fixed costs. She therefore gave the study less weight than in prior proceedings. The ALJ gave significant weight to the fact that there have been a number of customer-charge increases in recent years. And she found that if the Commission adopts a decoupling mechanism, it would remove the need to increase the customer charges to support Xcel's revenue stability.

For these reasons, the ALJ recommended that the Commission retain the current Residential and Small General Service customer charges.

D. Commission Action

The Commission concurs with the ALJ and adopts her recommendation to retain the existing customer charges for residential and small general-service customers.

In setting rates, the Commission must consider both ability to pay and the need to encourage energy conservation.[86] The Commission must balance these factors against the requirement that the rates set not be "unreasonably preferential, unreasonably prejudicial, or discriminatory"[87] and the utility's need for revenue sufficient to enable it to provide service.[88]

The Commission concludes that raising the Residential and Small General Service customer charges, even by the smaller amount the Department recommends, 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 notes that Xcel's Residential Overhead Service customer charge nearly doubled between 2004 and 2014, with four of the increases coming in just the last five years. 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.

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.

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[86] *See* Minn. Stat. §§ 216B.16, subd. 15, 216B.03.

[87] Minn. Stat. § 216B.03.

[88] Minn. Stat. § 216B.16, subd. 6.

Xcel and the Department argued that the current customer charges are set below cost and will result in intraclass subsidies. However, the Clean Energy Intervenors and the OAG have cast doubt on the validity of Xcel's class-cost-of-service study as a means of apportioning intraclass responsibility for fixed costs. Therefore, the Commission, like the ALJ, gives the study limited weight.

For the foregoing reasons, the Commission will require that Xcel retain the existing customer charges for Residential and Small General Service customers.

XXXVII. Interruptible-Service Discounts

A. The Issue

Customers who take interruptible service agree to have their service interrupted when called upon by Xcel or face high penalties. The Company and its ratepayers benefit from interruptible load by not having to build or acquire the additional generation to serve it.

Xcel sets interruptible-service discounts at the lowest level it believes will attract enough interruptible load to meet short-term load-shedding needs and permit long-term planning. To maintain an optimal supply of interruptible load, Xcel proposed to increase the discount for each of the six interruptible-service classes by an average of 5.15%.

The Chamber and XLI recommended increasing interruptible discounts beyond the level Xcel proposed, emphasizing the benefit of interruptible load to Xcel's system and the possibility that customers will drop out of the program if the discount is not increased.

The Department recommended a more modest increase of about 3%. It argued that a smaller increase was appropriate given the limited number of service interruptions over the last several years and the Company's claim that it currently has sufficient levels of interruptible load.

The ALJ agreed with the Department, finding that the other parties had failed to demonstrate that a larger increase was necessary to maintain an optimal supply of interruptible load.

B. Commission Action

The Commission concurs with the ALJ and adopts her findings and recommendation. The Department's proposal to increase the C-class interruptible-service discounts by 3% and increase the remaining discounts proportionately appears reasonably targeted to maintain a sufficient level of interruptible load.

The Chamber argued that a greater increase was necessary to maintain adequate interruptible load, asserting that Xcel has lost interruptible customers in recent years. However, the Chamber did not provide evidence linking the decrease in interruptible customers to the discount level. Moreover, interruptible load is closely monitored by the Company, and the discounts are examined in every rate-setting proceeding. Thus, any significant downward trend in interruptible load can be timely addressed.

XXXVIII. Inclining-Block Rates

A. The Issue

The Clean Energy Intervenors proposed a four-tier inclining-block-rate (IBR) structure for the residential customer class. Under the proposal, per-kWh energy rates would rise as a customer's usage passes three thresholds: 350 kWh, 700 kWh, and 1,200 kWh.[89] The Clean Energy Intervenors argued that the IBR structure would encourage conservation and was in the public interest.

Xcel initially opposed an IBR structure but later entered into a stipulation with the Clean Energy Intervenors, ECC, and the Suburban Rate Authority asking the Commission to open a separate docket to give the parties more time to develop an IBR proposal. The stipulation allows Xcel to submit one alternative to the Clean Energy Intervenors' proposal but does not expressly permit any other party to submit an alternative.

The Department did not sign the stipulation but agreed that the issue of inclining block rates would be better resolved outside this rate case. It committed to hold stakeholder meetings to review IBR proposals and issue a report to the Commission.

The OAG opposed the Clean Energy Intervenors' proposal, arguing that it would have negative consequences for certain ratepayers, particularly those with limited ability to alter their energy consumption. Further, the OAG argued that the stipulation was too restrictive in limiting the discussion to only the Clean Energy Intervenors' and the Company's IBR proposals.

The Administrative Law Judge agreed with the parties to the stipulation that inclining block rates would be an effective tool to promote conservation and that the issue warrants further review. The ALJ suggested two modifications to the process set forth in the stipulation: (1) allow all parties to submit alternative IBR proposals and (2) require that the parties to the stakeholder meetings specifically address potential impacts on high-use, low-income ratepayers.

B. Commission Action

The Commission concurs with the ALJ's recommendation to approve the stipulation, and will do so with the modifications outlined below.

The Commission agrees that inclining block rates should be examined in a separate docket. A separate proceeding, without the time pressure of a rate case, will allow careful consideration of the Clean Energy Intervenors' proposal and the effect an IBR structure would have on low-income customers who are unable to limit their usage in response to the conservation price signals sent by the inclining blocks.

Further, the Commission concludes that the discussion should be expanded to include consideration of other possible alternative rate designs that promote energy conservation, reduce peak demand, and/or send more accurate, useful price signals to customers. Facilitating a broader discussion of alternatives will create the best possible chance of the process resulting in a

[89] These thresholds apply during the summer season. The proposed winter IBR thresholds are 300 kWh, 600 kWh, and 1,000 kWh.

proposal that is acceptable to all parties and that treats all customer classes in a fair and equitable manner.

So that any proposal by Xcel may be informed by the stakeholder meetings and the Department's resulting report, the process should begin with stakeholder meetings. The Department should complete stakeholder meetings and issue a report to the Commission on the stakeholder process within 180 days of this order. Once the Department's report is filed, the Commission will determine whether to require Xcel to file a proposal for an IBR structure or any rate-design alternative that furthers the goals identified above.

XXXIX. Coincident-Peak Billing

A. The Issue

The Chamber proposed that the Commission require Xcel to modify its tariff to facilitate coincident-peak billing. Under coincident-peak billing, Xcel would aggregate the meter readings of customers with multiple metered locations on a single business site, including meters on contiguous properties. This billing method would reduce the total billed demand of customers with multiple demand-billed meters on a single site.

Xcel opposed the Chamber's proposal, arguing that coincident-peak billing would be costly to implement and would benefit only nine large commercial and industrial customers. The Company also argued that coincident-peak billing was unnecessary because large customers already have the ability to change their wiring configuration to facilitate aggregated demand billing through a single meter.

The Administrative Law Judge noted that the Commission had declined to adopt a similar proposal by the Chamber in Xcel's last rate case because it was not sufficiently developed. While she found the current proposal to be an improvement, the ALJ concluded that it was still not sufficiently developed to show that coincident-peak billing will result in reasonable rates.

B. Commission Action

The Commission concurs with the ALJ and adopts her recommendation to deny the Chamber's proposal for coincident-peak billing.

The Chamber has not fully addressed who will bear the cost of its proposal, stating only that it is not opposed to a reasonable meter charge to recover billing-process changes. Nor has the Chamber demonstrated that it would be cost-effective for any of the nine potentially eligible customers to implement coincident-peak billing if the customer is responsible for the cost of the new meters as well as a reasonable meter charge.

For these reasons, the Commission concurs with the ALJ that the Chamber's proposal for coincident-peak billing is still not sufficiently developed to demonstrate that it will result in reasonable rates.

XL. Definition of "Contiguous"

A. The Issue

Xcel's tariff provides that a customer may combine electric service for two or more buildings located on the same parcel or on contiguous parcels.[90] The tariff does not define "contiguous."

The Chamber claimed that Xcel has been interpreting "contiguous" to deny applications for combined electric service when property lines are interrupted by roadways and other rights of way. It asked the Commission to require Xcel to adopt the definition of "contiguous property" set forth in Minn. Stat. § 216B.164, subd. 2a(e): "property owned or leased by the customer sharing a common border, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way, or utility rights-of-way."

Xcel opposed the Chamber's request. The Company stated that it understands "contiguous" property to be "a single physical customer site or location, as distinct from customer accounts at different geographical locations." Xcel argued that there is no need to further define "contiguous," since a customer is free to wire its site in a way that presents one metered service location.

The Administrative Law Judge concluded that the Chamber's request to incorporate the statutory definition of "contiguous property" into Xcel's tariff was reasonable.

B. Commission Action

The Commission declines to adopt the Administrative Laws Judge's recommendation to require Xcel to incorporate the definition of "contiguous property" from Minn. Stat. § 216B.164, subd. 2a(e), into its tariff. The Commission is concerned that this definition, which comes from a statute governing distributed generation, may not be ideally suited to other contexts and may result in unintended consequences.

However, the Commission agrees that all parties would benefit from clarity and consistency in the definition of "contiguous property" in Xcel's tariff. The Commission will therefore require Xcel to file a definition of the term "contiguous property" as used in section 6, sheet 19.3 of the Company's Electric Rate Book.

XLI. Renewable-Energy-Purchase Tariff

A. The Issue

XLI asked the Commission to require Xcel to develop a tariff for buying and selling renewable energy directly to qualifying large high-load-factor customers. While the Company has a voluntary wind-energy purchase program (Windsource), the rates are higher than non-Windsource rates. XLI asked that Xcel be required to work with interested parties to develop a renewable-energy-purchase tariff to be filed no later than the Company's next rate case.

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[90] Minnesota Electric Rate Book section 6, sheet 19.3.

Xcel is interested in discussing a renewable-energy-purchase tariff with XLI and other interested stakeholders. However, the Company opposed setting a deadline, anticipating that developing a tariff proposal will take substantial time.

The Administrative Law Judge recommended that Xcel be required to propose a renewable-energy-purchase tariff in its next rate case.

B. Commission Action

While the Commission agrees that XLI's renewable-energy-purchase tariff proposal merits further discussion, the Commission declines to set a specific deadline for Xcel to present a new tariff. Instead, the Commission will order the Company to work with XLI and other interested stakeholders to develop a renewable-energy-purchase program that addresses the goals outlined by XLI in this case.[91] The program should also address the goals of creating demand for renewable energy beyond that required by the Renewable Energy Standard, Minn. Stat. § 216B.1691, and of meeting the reasonable-rate requirements of Minn. Stat. § 216B.03.

[91] The final tariff may, but need not, comply with the specific recommendations provided by XLI in Exhibit 260 (Pollock Direct) at pages 61–62.

FINANCIAL SCHEDULES AND COMPLIANCE

XLII. Overall Financial Schedules

A. Gross Revenue Deficiency

The above Commission findings and conclusions result in a total gross revenue deficiency of $58,908,000 for the 2014 test year and $105,854,000 for the 2015 Step as shown below:

Revenue Deficiency - Minnesota Jurisdiction
Test Year Ending December 31, 2014 & 2015 Step
($000's)

Line No.		2014 Test Year	2015 Step
1	Average Rate Base	$ 6,493,649	$ 584,573
2	Rate of Return	7.34%	7.37%
3	Required Operating Income	$ 476,634	$ 43,083
4	Operating Income before AFUDC	$ 407,232	$ (13,470)
5	AFUDC	$ 34,864	$ (5,509)
6	Total Operating Income	$ 442,096	$ (18,979)
5	Income Deficiency	$ 34,538	$ 62,062
6	Gross Revenue Conversion Factor	1.705611	1.705611
7	Gross Revenue Deficiency	$ 58,908	$ 105,854

B. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the 2014 test year is $6,493,649,000 and $584,573,000 for the 2015-Step additions as shown below:

Rate Base Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2014 & 2015 Step
($000's)

Line No.		2014 Test Year	2015 Step
	ELECTRIC PLANT IN SERVICE		
1	Production	$ 7,952,590	$ 642,103
2	Transmission	1,999,645	101,145
3	Distribution	3,019,969	(1,828)
4	General	499,761	12,133
5	Common	454,709	0
6	Total Utility Plant In Service	$ 13,926,674	$ 753,553
	RESERVE FOR DEPRECIATION		
7	Production	$ 4,452,331	$ 54,929
8	Transmission	566,980	(48,565)
9	Distribution	1,184,480	(79,218)
10	General	179,709	(1,480)
11	Common	243,128	1,391
12	Total Reserve For Depreciation	$ 6,626,628	$ (72,943)
	NET PLANT IN SERVICE		
13	Production	$ 3,500,259	$ 587,174
14	Transmission	1,432,665	149,710
15	Distribution	1,835,489	77,390
16	General	320,052	13,613
17	Common	211,581	(1,391)
18	Net Utility Plant In Service	$ 7,300,046	$ 826,496
19	Construction Work in Progress	$ 529,838	$ (111,525)
20	Accumulated Deferred Income Taxes	$ (1,604,789)	$ (126,206)
21	Cash Working Capital	$ (74,321)	$ (4,192)
	OTHER RATE BASE		
22	Materials & Supplies	$ 116,514	0
23	Fuel Inventory	74,663	0
24	Non-Plant Assets & Liabilities	(12,904)	0
25	Prepayments	14,103	0
26	Nuclear Outage Amortization	82,801	0
27	Customer Advances	(3,301)	0
28	Customer Deposits	(2,763)	0
29	Sherco 3 Deferral	10,250	0
30	Black Dog Reg Asset Amortization	2,961	0
31	PI EPU Amortization	55,349	0
32	Other Working Capital	5,202	0
33	Total Other Rate Base	$ 342,875	0
34	TOTAL AVERAGE RATE BASE	$ 6,493,649	$ 584,573

C. Operating Income Summary

Based on the above findings, the Commission concludes that the appropriate operating income for the 2014 test year under present rates is $442,096,001 and for the 2015-Step additions is $(18,979,000) as shown below:

Operating Income Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2014 & 2015 Step
($000's)

Line No.		2014 Test Year		2015 Step	
	UTILITY OPERATING REVENUES				
1	Retail Revenue	$	2,826,039	$	622
2	Interdepartmental		962		0
3	Other Operating Revenue		621,402		56,829
4	Total Operating Revenue	$	3,448,403	$	57,451
	EXPENSES				
	Operating Expenses				
5	Fuel & Purchased Energy	$	1,086,327		0
6	Power Production		697,188		4,379
7	Transmission		191,916		0
8	Distribution		103,490		(173)
9	Customer Accounting		48,552		0
10	Customer Service & Information		92,987		0
11	Sales, Econ Dvlp & Other		101		0
12	Administrative and General		190,225		0
13	Total Operating Expenses	$	2,410,786	$	4,206
14	Depreciation Expense	$	273,308	$	81,958
15	Amortization	$	31,300		0
	Taxes:				
16	Property	$	154,355	$	4,016
17	Deferred Income Tax & ITC		161,968		14,815
18	Federal &State Income Tax		(19,955)		(34,074)
19	Payroll & Other		29,409		0
20	Total Taxes	$	325,777	$	(15,243)
21	TOTAL EXPENSES	$	3,041,171	$	70,921
22	AFUDC	$	34,864	$	(5,509)
23	TOTAL OPERATING INCOME	$	442,096	$	(18,979)

XLIII. Compliance Filing Required

The Commission will require the Company to make a compliance filing within 30 days of the date of this order showing the final rate effects of the decisions made here and proposing a plan for refunding the difference between the amounts it collected in interim rates and the amounts it is authorized to collect in final rates. The Commission will establish a brief comment period to give interested persons a chance to review and comment on that filing.

ORDER

1. Xcel's Electric Utility is entitled to increase Minnesota jurisdictional revenues by $58,908,000 to produce jurisdictional total retail-related revenue of $2,885,909,000 for the test year ending December 31, 2014 and to produce jurisdictional total retail-related revenue of $2,992,385,000 for the 2015 Step.

2. The Commission accepts, adopts, and incorporates the findings, conclusions, and recommendations of the Administrative Law Judge, except as set forth in this order.

3. Xcel shall exclude the 2014 depreciation expense and return on the Monticello EPU from the 2014 test year based on a 50% allocation to the EPU. Xcel is authorized to recover the EPU costs in the 2015 Step, but if the EPU is not in service by January 1, 2015, the Company shall refund any excess amounts collected through the refund mechanism for the multiyear rate plan.

4. The disallowance of 2014 Monticello EPU depreciation expense shall be a permanent disallowance. The Company shall reduce Construction Work in Progress by this amount, or if the plant is shown as being included in Plant in Service, the disallowed depreciation expense will remain in the depreciation reserve. Xcel shall make a compliance filing within ten days of this order providing the accounting entries and explaining how this permanent disallowance is reflected in its accounting records.

5. Xcel is authorized to recover $950,000 in Monticello prudency-review costs with a two-year amortization period. If the Company does not file its next rate within this two-year period, it shall return any over-recovery to customers when it files its next rate case.

6. The Company shall use 5.05% (a five-year average of discount rates determined under Financial Accounting Standard 87) as the approved discount rate to determine its XES Plan pension costs for ratemaking purposes.

7. The Company shall apply the rolling five-year average FAS 87 discount rate when determining the XES Plan cost subject to deferral (or reversal) in subsequent years (i.e., non–rate-case test years) as the 2012 mitigation established in Docket No. E-002/GR-12-961 continues.

8. The Commission adopts ALJ Finding 126, excluding the following sentence: "For that reason, use of the FAS 87 bond-matching discount rate will help ensure that the XES Plan, which is subject to FAS 87, is fully funded."

9. The Commission adopts ALJ Finding 157 with the following modification:

> 157. ~~Finally, contrary to the Department's assertion, there is no benefit to the shareholders from this longstanding approach to calculating pension expense because the Company~~ The pension fund does not pay out the gains to shareholders. Instead, the gains help to reduce rate increases by limiting the future pension expense.

10. The qualified pension asset and associated deferred-tax amounts shall be included in rate base. For rate-base purposes, the pension asset is to reflect the cumulative difference between actual cash deposits made by the Company reduced by the recognized qualified pension cost determined under the ACM/FAS 87 methods since plan inception, not to exceed the Company's filed request. The Company shall provide a detailed compliance filing which explains the calculated amount within ten days of the Commission's decision.

11. In the initial filing of its next electric rate case, the Company shall

    a. Address why the target asset allocations for its pension fund are reasonable, including ages of retirees and employees. The Company must provide an update to its existing Exhibit 31 (Tyson Rebuttal), Schedule 1 and expand it to include this demographic information.

    b. Provide testimony on its investment strategies and target asset allocations for the qualified pension fund and the justifications for those decisions, for the period from 2007 to the date of its next filing.

    c. Provide copies of the actuarial reports used to determine employee benefit costs, including its schedules denoting each subsidiary's cost assignments for each benefit. The Company must also include workpapers that show the derivation of the jurisdictional portion of each benefit cost.

    d. Provide testimony that identifies and discusses each non-qualified employee-benefit cost included in its test years.

    e. Include testimony identifying the basis used for its requested rate-base impact related to pensions. Additional schedules must be included that reflect the underlying calculation of the qualified pension asset (or liability) balances requested for rate-base inclusion.

12. The Commission approves including the identified 2008-market-loss amortized amounts in the calculated pension and retiree medical benefit costs.

13. The discount rate used to calculate retiree medical benefit costs for ratemaking purposes shall be set to equal 5.08%, the five-year average of the FAS 106-based discount rates.

14. Any amount by which the qualified pension expense allowed in rates exceeds future years' qualified pension expense (calculated using the Commission-approved discount-rate point of reference) the Company shall apply toward the recovery of the accumulated deferred XES Plan costs. "Future years" includes 2015, and each subsequent year's qualified pension expense if not a rate-case test year. The recoverable XES Plan expense

amount shall be calculated using the proximate measurement date appropriate for each operating year (12/31/2013 for 2014; 12/31/2014 for 2015, etc.) until the next rate case. The Company shall file annual compliance reports which provide its pension plans' cost-calculation reports, the XES Plan accumulated deferred balance, and the excess rate-level recovery applied toward satisfying the deferral. Deferred amounts shall not be included in rate base.

15. The Commission approves the retiree medical benefit cost level in rates that is the calculated average of the annual projected benefit cost over the expected two-year rate life. Each year's projected cost amount subject to averaging must be calculated using the Commission-approved assumptions and the most proximate measurement date applicable to each year.

16. In the initial filing of its next electric rate case, the Company shall

    a. discuss the cost components of the postretirement benefits plans cost (other than pensions) affecting Minnesota rates, particularly the drivers of the amortization of net gain/loss amount and the reasons this component amount has varied since its last rate case (Docket No. E-002/GR-13-868); and

    b. provide the report of future years' actuarial cost projections of the postretirement benefits (other than pensions), clearly identifying the assumptions and measurement point used to develop these projections.

17. In its next rate case the Company shall provide historical active health care costs since 2011 for each calendar year, including both the per-book amount and the actual claims expense. The Company shall also provide information detailing the annual year-end Incurred But Not Reported (IBNR) accruals and subsequent reversals.

18. The Company shall reduce its 2015-Step rate base by $535,552 to reflect 2015 capital retirements of transmission and distribution facilities.

19. The 2014 and 2015 revenue requirements shall be calculated using the 2014-test-year and 2015-Step replacement projects specified in Ms. Perkett's Rebuttal Testimony, Schedule 11.

20. The Company may include the unamortized nuclear-refueling-outage costs in rate base and earn the overall allowed rate of return on that balance.

21. The Company shall recover the cost of its Pleasant Valley and Border Winds facilities through base rates, using the average of the beginning- and end-of-year plant balances, consistent with the treatment of other capital investment, and subject to true-up in its Renewable Energy Standard rider.

22. The Company shall include in base rates the production tax credits associated with the operation of the Pleasant Valley and Border Winds facilities, in the amount disclosed in nonpublic Exhibit 432, Schedule NAC-7, which reduces the 2015-Step revenue requirement by $11.093 million.

23. The Company shall notify the Commission and report and capture potential cost reductions or other forms of compensation that may result from contract changes or contractors' failure to meet contract terms for either the Pleasant Valley or the Border

Wind projects. Such cost reductions and compensation payments will be subject to Commission review for potential credits or refunds to ratepayers.

24. By September 1, 2015, or in its next Renewable Energy Standard-rider filing, the Company shall report the results of stakeholder discussions on alternative cost-recovery formulas for the Pleasant Valley and Border Winds projects designed to allocate risks and create incentives.

25. Because the Company's 50% cost reduction to the jurisdictional corporate-aviation costs does not capture the removal of flight costs that were incurred for reasons other than for the provision of utility service, the Commission does not adopt ALJ Finding 559. Allowable corporate-aviation costs shall be further reduced by the cost of flights categorized by the following business-purpose reasons:

    a. Personal Travel (34 total company flights);

    b. Investor Relations (45 total company flights).

26. The following reported business purposes for corporate travel are insufficient and do not permit the Commission to determine if the expense was reasonably and necessarily incurred for the provision of utility service, fail to meet the requirements of Minn. Stat. § 216B.16, subd. 17, and are disallowed. The Company shall reduce the corporate-aviation costs further by the cost of flights for each flight with the stated description:

    a. Business Area Travel (1,668 total company flights);

    b. Director Travel (615 total company flights);

    c. Manager Travel (55 total company flights);

    d. Xcel Executive Business Travel (831 total company flights).

27. The Commission does not adopt ALJ Findings 562 and 563 but adopts the following in the place of ALJ Finding 562:

> 562. Minnesota law requires Xcel to provide information about the "business purpose" of each flight before recovery is permissible. Xcel did not meet this requirement because the "business purpose" descriptions in Xcel's flight log do not provide any information to determine the true business purpose of the flights. Because Xcel has not demonstrated that the flights coded as Executive Business Travel, Director Travel, Manager Travel and Business Area Travel have a "business purpose" that indicates they are necessary for the provision of utility service, they must be disallowed. The Company is required to conduct an annual shareholders' meeting and documentation shows the designated "Shareholders Meeting" travel occurred close in time to the annual meeting.

28. The Commission adopts ALJ Finding 564 modified to read as follows:

> The Commission orders the Company in future rate cases seeking recovery of corporate aviation to provide more detailed, accurate records of the actual business purpose for flights that are scheduled, rather than reducing all flights to a generic "code."

29. The Company has complied with the filing requirements set in its last rate case (Docket No. E-002/GR-12-961) regarding its Annual Incentive Compensation Program and shall continue to provide similar information and documents in any future rate case in which it seeks rate recovery of incentive-compensation costs.

30. In its next electric rate case, the Company shall

    a. present a new key performance indicator (KPI) for transmission O&M costs;

    b. provide a comparison study of its transmission O&M costs by using appropriate peer companies, along with justification for why certain utilities were included or excluded; and

    c. propose a new cost control KPI at the vice-presidential level for overall transmission costs.

31. Upon resolution of the lawsuit involving Babcock & Wilcox Nuclear Energy, Inc., the Company shall make a compliance filing providing all relevant information as to costs and interest paid and discuss what costs were included as Plant in Service in this rate case.

32. Any costs included in rate base but not paid shall be refunded as part of either the 2014 or 2015 refunds. If the lawsuit is not resolved at either of those times, then the refund should be made within 60 days after the lawsuit is resolved.

33. The Company shall make a compliance filing within 30 days of completing the refund. The compliance filing should provide information detailing the refund and about the resolution of the lawsuit. The compliance filing should describe the amount not paid to Babcock & Wilcox that remains in rate base and the revenue-requirement effect of that amount so the Commission can consider whether to require Xcel to track that amount for return to ratepayers in Xcel's first rate case subsequent to the resolution of the lawsuit.

34. The Commission adopts the weather-normalized sales data in Xcel's January 16, 2015 compliance filing for rate-making purposes.

35. Xcel shall modify its 2014 and 2015 class-cost-of-service studies to classify the costs of the Grand Meadow and Nobles wind farms on the same basis as its other fixed production-plant costs using the plant-stratification method.

36. Xcel shall modify its 2014 and 2015 class-cost-of-service studies to use the location method rather than the predominant-nature method to allocate other production O&M costs.

37. In its next rate case, Xcel shall refine its class-cost-of-service study cost-allocation method by identifying any and all other production O&M costs that vary directly with the amount of energy produced based on Xcel's analysis. If Xcel's analysis shows that such costs exist, then Xcel should classify these costs as energy-related and allocate them using appropriate energy allocators, while allocating the remainder of other production O&M costs on the basis of the production plant.

38. In its next rate case the Company's class-cost-of-service study shall include an explanatory filing identifying and describing each allocation method used in the study and detailing the reasons for concluding that each allocation method is appropriate and superior to other allocation methods considered by the Company, whether those methods are based on the Manual of the National Association of Regulatory Utility Commissioners or the Company's specific system requirements, its experience, and its engineering and operating characteristics. The Company shall also explain its reasoning in cases in which it did not consider alternative methods of allocation or classification.

39. In its next rate case, Xcel shall provide parties with data sufficient to verify and reproduce its minimum-system study and shall file a zero-intercept analysis of distribution costs, or explain why it was not able to collect the data necessary to do so.

40. Xcel shall implement its proposed revenue decoupling mechanism (RDM) for its residential and small business customer groups with the following modifications:

    a. *Pilot Program*: Xcel shall implement its revenue decoupling mechanism as a three-year pilot program.

    b. *Start of energy-consumption measurement*: Xcel may begin calculating its over- or under-recovery of nonfuel costs after the final compliance order authorizing implementation of final rates in this proceeding, but not before new rates take effect, and no sooner than January 1, 2016.

    c. *Limits on upward rate adjustments*:

        - *Energy savings requirement*: In any year in which Xcel fails to achieve energy savings equal to 1.2% of retail sales, Xcel will forgo the opportunity to make an upward rate adjustment via the revenue decoupling mechanism in the following year.

        - *Cap*: In any year in which the revenue decoupling mechanism would authorize an upward adjustment to recover more than 3% of a customer group's base revenues (excluding consideration of Xcel's fuel clause or other riders), Xcel may implement a 3% adjustment. Xcel may also petition to use the following year's decoupling adjustment to recover costs that were excluded from recovery by this cap. In the petition, Xcel must demonstrate that Xcel's demand-side-management programs and other company initiatives were a substantial contributing factor to the declining energy sales triggering the rate adjustment, and that other nonconservation factors were not the primary factors for the declining sales.

d. *Customer education*: Xcel shall file a plan for implementing an education and outreach program for its customers explaining the goals and operations of its RDM program.

e. *Annual report*: Xcel shall submit an annual report to the Commission by February 1 of each year prior to any application of a RDM adjustment factor on April 1. The report shall include the following information:

i. Total over- or under-collection of allowed revenues by customer class or group;

ii. Total collection of prior deferred revenue;

iii. Calculations of the RDM deferral amounts;

iv. The number of customer complaints;

v. The amount of revenues stabilized and how the stabilization impacted Xcel's overall risk profile;

vi. A comparison of how revenues under traditional regulation would have differed from those collected under partial and full decoupling;

vii. A description of all new and existing demand-side-management programs and other conservation initiatives Xcel had in effect for the year covered by the report;

viii. A description of the effectiveness of all new and existing demand-side-management programs and other conservation initiatives Xcel had in effect for the year covered by the report; and

ix. Other factors that may have contributed to a decline in energy consumption, including weather and the economy.

41. The Company shall continue its current practice of collecting Conservation Improvement Program (CIP) costs through base rates, subject to true-up through the Resource Adjustment Charge.

42. The Company shall not change historical data in Windsource and Fuel Clause Adjustment filings without identifying and providing a justification for the changes. The Company shall clarify in each Fuel Clause Adjustment and Windsource filing what costs are included in the Windsource Contract Payments.

43. The Company shall address the issues raised by Mr. Schedin in his testimony in this case as part of the Commission's generic proceeding on standby service, Docket No. E-999/CI-15-115.

44. Xcel shall increase the Level C Performance Factor interruptible-service discounts by 3% and institute corresponding increases for the other performance factors to maintain the current relationship between tiers.

45. The Commission approves the process and substance outlined in the IBR Stipulation, with the following additional modifications:

    a. In addition to IBR, the process should consider other alternative rate designs that result in rates that promote energy conservation, reduce peak demand, and/or send more accurate, useful price signals to customers.

    b. In order to allow a potential proposal to be informed by the stakeholder meetings and the Department's resulting report, the process should begin with stakeholder meetings convened by the Department.

    c. The Department should complete stakeholder meetings and issue a report to the Commission on the stakeholder process within 180 days of this order.

    d. After the Department's report is filed, the Commission will determine whether to require the Company to file a proposal for an IBR structure or any alternative rate-design proposals that further the goals identified above.

    The Commission delegates to the Executive Secretary the authority to modify the timelines set forth above as necessary. The Commission does not adopt Finding 841 of the ALJ's Report to the extent that it is inconsistent with the preceding decisions.

46. Xcel shall file a definition of the term "contiguous property" for application in the Company's Electric Rate Book section 6, sheet 19.3.

47. Xcel shall work with XLI and other interested stakeholders to develop a renewable-energy-purchase program that addresses the goals outlined by XLI in this case, such as increasing the competitiveness of industrial rates. The program should also address the goals of creating demand for renewable energy beyond that required by the Renewable Energy Standard, Minn. Stat. § 216B.1691, and of meeting the reasonable-rate requirements of Minn. Stat. § 216B.03. The final tariff may, but need not, comply with the specific recommendations provided by XLI in Exhibit 260 (Pollock Direct) at pages 61–62.

48. The Company shall rerun the CCOSS in accordance with all Commission decisions in this docket and the Monticello docket that affect the CCOSS, and set the class revenue apportionment by applying the following methodology to the revised CCOSS:

    a. Maintain the current level of Lighting class revenues;

    b. Set the C&I Non-Demand class apportionment at the cost-based level;

    c. If the revised CCOSS shows that the Residential class is currently contributing more than its share of cost, set the Residential class apportionment at the cost-based level;

    d. If the revised CCOSS shows the Residential class is currently contributing less than its share of cost, move the Residential class 75% closer to cost; and

    e. Recover the remaining revenue requirement from the C&I Demand class.

49. The Company shall make a filing within 30 days of the final determination in this case if final authorized rates are higher or lower than interim rates. The filing shall contain a proposal to make adjustments of interim rates consistent with the Commission's decision in this proceeding, to affected customers. The Company shall calculate the following amounts:

    a. The refunds due for 2014, based on the interim-rate collections during 2014 and final rates in effect as of January 1, 2014; and

    b. The amount of under-collection or over-collection for 2015, based on the interim-rate collections in 2015 through the date of the Commission's final determination, compared with each of the following:

        i. the final dates for 2015, if effective on January 1, 2015; and

        ii. the final rates for 2015, if effective on the date of the Commission's final determination.

50. Parties wishing to comment on the interim-rates-proposal filing discussed above shall file comments within 20 days. Comments should address the Company's proposal, including whether the proposal is consistent with

    a. The interim-rate statute, Minn. Stat. § 216B.16, subd. 3, including the provision in Minn. Stat. § 216B.16, subd. 3(c), for implementation of the new revenue requirement ("If, at the time of its final determination, the commission finds that the interim rates are less than the rates in the final determination, the commission shall prescribe a method by which the utility will recover the difference in revenues between the date of the final determination and the date the new rate schedules are put into effect.");

    b. Minn. Stat. § 216B.16, subd. 3(b), prohibiting changes in rate design while interim rates are in effect. ("[T]he interim rate schedule shall be calculated using the proposed test year cost of capital, rate base, and expenses, except that it shall include . . . no change in the existing rate design.");

    c. The multiyear-rate-plan statute, Minn. Stat § 216B.16, subd. 19, and the Commission's June 17, 2013 Multiyear Rate Plan Order (Docket No. E,G-999/M-12-587); and

    d. The various approved extensions to the length of this proceeding.

51. The Company shall provide a refund to ratepayers if the Company's actual capital-related revenue requirement is less in total in 2014 than the Commission authorizes for the 2014 test year. Such a refund would be based on the Company's total actual capital revenue requirements compared to the Commission's authorized amount, but would not be done on a project-by-project basis.

52. The true-up for capital costs in 2015 shall be conducted on a project-by-project basis for those project costs included in the 2015 Step. If the total actual 2015-Step revenue requirement is lower than the total test-year 2015 Step authorized by the Commission, the Company shall provide a refund to customers.

53. Within 30 days of the date of this order, the Company shall make the following compliance filings:

    a. Revised schedules of rates and charges reflecting the revenue requirement and the rate-design decisions herein, along with the proposed effective date, and including the following information:

        i. Breakdown of Total Operating Revenues by type.

        ii. Schedules showing all billing determinants for the retail sales (and sale for resale) of electricity. These schedules shall include but not be limited to

            - Total revenue by customer class;

            - Total number of customers, the customer charge, and total customer-charge revenue by customer class; and

            - For each customer class, the total number of energy- and demand-related billing units, the-per unit energy and demand cost of energy, and the total energy- and demand-related sales revenues.

        iii. Revised tariff sheets incorporating authorized rate-design decisions.

        iv. Proposed customer notices explaining the final rates, the monthly basic service charges, and any and all changes to rate design and customer billing.

    b. A revised base cost of energy, supporting schedules, and revised fuel-adjustment tariffs to be in effect on the date final rates are implemented.

    c. A summary listing of all other rate riders and charges in effect, and continuing, after the date final rates are implemented.

    d. A computation of the Conservation Cost Recovery Charge (CCRC) based upon the decisions made herein for inclusion in the final order. The filing shall include a schedule detailing the CIP tracker balance at the beginning of interim rates, the revenues (CCRC and CIP Adjustment Factor) and costs recorded during the period of interim rates, and the CIP tracker balance at the time final rates become effective.

54. Any comments on compliance filings shall be filed within 30 days of the date of the compliance filing. Comments are not necessary on the Company's proposed customer notice.

55. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf

Daniel P. Wolf
Executive Secretary

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USDA

United States Department of Agriculture

Characteristics of Supplemental Nutrition Assistance Program Households: Fiscal Year 2014

Supplemental Nutrition Assistance Program
Nutrition Assistance Program Report Series
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Report No. SNAP-15-CHAR

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Characteristics of Supplemental Nutrition Assistance Program Households: Fiscal Year 2014

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EXECUTIVE SUMMARY

The Supplemental Nutrition Assistance Program (SNAP) serves as the foundation of America's national nutrition safety net. It is the nation's first line of defense against food insecurity and offers a powerful tool to improve nutrition among low-income individuals. SNAP is the largest of the 15 domestic food and nutrition assistance programs administered by the Food and Nutrition Service (FNS) of the U.S. Department of Agriculture (USDA). This report describes the characteristics of SNAP households and participants nationwide in fiscal year 2014 (October 2013 through September 2014). It also presents an overview of SNAP eligibility requirements and benefit levels in fiscal year 2014. The appendices provide detailed tabulations of household and participant characteristics for the nation and by State, as well as a brief description of the sample design and the sampling error associated with the estimates presented in the report.

SNAP Participation and Costs

In an average month in fiscal year 2014, SNAP provided benefits to 46.5 million people living in nearly 22.7 million households across the United States. The total federal cost of the Program in fiscal year 2014 was $74.2 billion, $70.0 billion of which went to SNAP benefits with the remainder going to program administration. The average monthly SNAP benefit across all participating households in fiscal year 2014 was $257.

The participant counts and benefit costs discussed in this section are based on FNS administrative records and thus differ slightly from estimates based on the SNAP Quality Control (SNAP QC) sample file (see Appendix D for an explanation of the differences). The remainder of this summary draws on data from the SNAP QC file.

Characteristics of SNAP Households and Participants

In fiscal year 2014, approximately 84 percent of SNAP households lived in poverty, as measured by the federal poverty guideline issued by the U.S. Department of Health and Human Services (HHS) (Appendix C). Forty-three percent of SNAP households had gross incomes that were less than or equal to half of the poverty guideline; these households received 58 percent of all benefits. With the value of SNAP benefits included as income, 10 percent of SNAP households would move above the poverty guideline and 13 percent would move from below half to above half of the poverty guideline.

Twenty-two percent of SNAP households had zero gross income in fiscal year 2014 and 41 percent had zero net income. Thirty-one percent of SNAP households had earned income, 20 percent received Supplemental Security Income (SSI), 25 percent received Social Security income, 8 percent received Child Support Enforcement payments, 6 percent received support from Temporary Assistance for Needy Families (TANF), 3 percent received State General Assistance benefits, and 2 percent received unemployment income. None of these percentages changed by more than 2 percentage points from fiscal year 2013 to fiscal year 2014.

Seventy-six percent of SNAP households included a child, an elderly individual, or an individual with a disability; these households received 82 percent of all benefits. Households with children received an average monthly SNAP benefit of $390, reflecting their larger average household size. The average household with children had 3.2 people, compared with an average of 1.1 people for households without children. A majority (57 percent) of SNAP households with children were single-adult households. Only 16 percent of these single-adult households with children received cash benefits from TANF. More than half (52 percent) of all SNAP households with children had earned income; 42 percent of single-adult households with children and 64 percent of multiple-adult households with children had earned income. Three percent of all households with children had both TANF and earned income.

Households with elderly individuals received an average monthly SNAP benefit of $129, reflecting their smaller-than-average size (1.3 people) and higher-than-average income compared to other SNAP participants. Eighty-two percent of SNAP households with elderly individuals consisted of an elderly individual living alone. These individuals received an average monthly benefit of $110, compared with an average monthly benefit of $212 for households with elderly individuals not living alone and $283 for households without any elderly individuals.

In fiscal year 2014, 64 percent of all SNAP participants were either children (44 percent), elderly adults (10 percent), or non-elderly adults with disabilities (10 percent). Just over half (56 percent) of all participants were female. About two-thirds (69 percent) of children were school age (age 5 to 17).

CHAPTER 1: INTRODUCTION

The Supplemental Nutrition Assistance Program (SNAP) is a central component of the nation's nutrition assistance safety net. SNAP's stated purpose is "to permit low-income households to obtain a more nutritious diet by increasing their purchasing power" (Food and Nutrition Act of 2008, as amended by the Food, Conservation, and Energy Act of 2008 [2008 Farm Bill], PL 110-246). SNAP is the largest of the 15 domestic food and nutrition assistance programs administered by the Food and Nutrition Service (FNS) of the U.S. Department of Agriculture (USDA). According to FNS administrative records, during fiscal year 2014, SNAP served approximately 46.5 million people in an average month, at a total annual cost of $74.2 billion, $70.0 billion of which went to SNAP benefits.[1]

SNAP is available to all individuals who meet the federal eligibility guidelines set by Congress and serves a broad demographic spectrum of the needy population. It provides benefits electronically via an Electronic Benefit Transfer (EBT) card; the benefits may be redeemed for eligible food items. As of September 30, 2014, 256,670 stores across the nation were authorized to accept SNAP benefits.

Federal, State, and local governments share the costs and administration of SNAP. Congress authorizes the program and appropriates necessary funds. USDA establishes SNAP regulations under the Food and Nutrition Act of 2008, as amended. FNS administers SNAP nationally, whereas State and local welfare agencies operate the program locally. The federal government fully funds SNAP benefits. The cooperating agencies share administrative costs, with FNS paying about 50 percent of such costs.

Using SNAP household data collected for quality control purposes, FNS publishes reports describing the characteristics of the SNAP population and uses the data for additional analyses. This report, the latest in an annual series that dates back to 1976, presents a picture of households and individuals participating in SNAP in fiscal year 2014. The report draws on data for participating households eligible for SNAP under normal program rules and thus does not include information about those who received disaster assistance nor those who were issued benefits mistakenly.[2]

In Chapter 2, we provide an overview of SNAP, including the regulations used to determine eligibility and benefits and the factors that affect program participation and costs, such as national economic trends. In Chapter 3, we describe the characteristics of households and individuals participating in SNAP in fiscal year 2014. We present detailed national tables of SNAP household characteristics in Appendix A and detailed State-by-State tables of SNAP household characteristics in Appendix B. Appendix C contains the fiscal year 2014 SNAP eligibility standards and maximum benefit amounts. In Appendix D, we provide a detailed explanation and evaluation of the source and reliability of the estimates in this report and in Appendix E we discuss the sampling error of the estimates. The data collection instrument used to collect the SNAP Quality Control (SNAP QC) data, which form the basis of this report, appears in Appendix F.

[1] The total cost of SNAP in fiscal year 2014 included $4.2 billion in other costs, including the federal share of State administrative costs, nutrition education, Employment and Training programs, benefit and retailer redemption and monitoring, payment accuracy monitoring, Electronic Benefit Transfer (EBT) systems, program evaluation and modernization efforts, as well as program access, health, and nutrition pilot projects.

[2] FNS coordinates with State, local, and volunteer organizations to provide food to those affected by storms, earthquakes, floods, or other disaster emergencies. About 2,000 people received disaster assistance at some time in fiscal year 2014. This number is calculated internally by Mathematica based on information provided by FNS, individual State reports, and direct contact with States. See Appendix D for more information on adjustments made to the data used for this report.

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CHAPTER 2: OVERVIEW OF THE SUPPLEMENTAL NUTRITION ASSISTANCE PROGRAM

The characteristics of SNAP households and the level of SNAP participation change over time in response to economic and demographic trends and legislative changes to SNAP. In this chapter, we explain SNAP eligibility requirements, application procedures, benefit computation, and benefit issuance. We conclude with a summary of program participation and costs, as well as a discussion on how the costs were related to the economy in fiscal year 2014.

Program Eligibility Requirements

The Agricultural Act of 2014 (the 2014 Farm Bill) reauthorized SNAP in February 2014. This legislation largely maintained the basic eligibility guidelines as defined under the 2008 Farm Bill. The Food and Nutrition Act of 2008, as amended, made some changes to the uniform national eligibility standards for SNAP, which were originally developed in the Food Stamp Act of 1977. These eligibility standards included defining a SNAP "household" and categories of households eligible for benefits. They also established gross and net income limits, a resource limit, and various nonfinancial criteria for eligibility. The legislation provided for exceptions to the eligibility criteria in certain high-cost areas, such as Alaska and Hawaii, and for certain individuals, such as those who are categorically eligible, elderly, or with disabilities.[3]

Furthermore, States have options to simplify certain eligibility rules. For example, States can waive recertification interviews for elderly individuals and individuals with disabilities who have no earned income, set requirements for reporting financial circumstances within various time frames, and determine penalties for failing to comply with work requirement programs. These options allow States greater flexibility to adapt to the needs of their own eligible populations.

In addition to maintaining basic eligibility requirements, the 2014 Farm Bill tightened the standards by which households can qualify for the shelter expense deduction based upon receipt of energy assistance, added SNAP funding for enhanced employment and training activities, and increased antifraud activities.

The Household

Under SNAP rules, a household is defined as individuals who live together and customarily purchase and prepare food together. Generally, individuals who live together in a residential unit but do not purchase and prepare food together may apply as separate household units; their incomes and countable resources are considered separately in eligibility and benefit determinations. However, spouses living together must apply together and parents must apply together with their children under age 22 who reside with them, even if the children have spouses or children of their own. Individuals

[3] A person is considered to be elderly for SNAP eligibility purposes if he or she is age 60 or older. Generally, a person is considered to be disabled for SNAP eligibility purposes if he or she receives federal or State disability or blindness payments or other disability retirement benefits from a government agency under the Social Security Act, including Supplemental Security Income (SSI) or Social Security disability or blindness payments; receives an annuity under the Railroad Retirement Act and is (1) eligible for Medicare or (2) considered to be disabled based on SSI rules; is a veteran who is totally disabled, permanently housebound, or in need of regular aid and attendance; or is permanently disabled and receiving veterans' benefits as a surviving spouse or child of a veteran.

who are elderly and cannot purchase and prepare food because of a substantial disability may apply as separate households from those with whom they reside as long as the gross monthly income of the remainder of their residential unit is less than 165 percent of the federal poverty guideline.[4] The incomes and countable resources of household members applying together for SNAP are aggregated to determine the household's eligibility and benefits.

Categorical Eligibility

Certain households are categorically eligible for SNAP and, therefore, not subject to the federal income and resource limits. Benefits for these categorically eligible households are determined under the same rules that apply to other eligible SNAP households and the level of benefits received is based on household income. All States confer categorical eligibility to SNAP households in which all members of the household receive or are authorized to receive Supplemental Security Income (SSI), Temporary Assistance for Needy Families (TANF), or General Assistance (GA) benefits. These households are known as pure public assistance households.

Over the past 15 years, categorical eligibility has expanded, eliminating certain verification requirements and simplifying the application and eligibility determination process for a much larger group of households. On November 21, 2000, a broader interpretation of existing categorical eligibility rules was implemented, requiring States to confer categorical eligibility on families receiving or certified as eligible to receive benefits or services—such as employment, child care, or transportation assistance—that are at least 50 percent funded by TANF or Maintenance of Effort funds. In addition, States have the option of conferring categorical eligibility on families receiving or certified to receive benefits or services that are less than 50 percent funded by TANF/Maintenance of Effort funds. They may also confer categorical eligibility on households in which at least one member receives the benefit or service and the State determines the entire household benefits. If the purpose of the program conferring categorical eligibility is to prevent out-of-wedlock pregnancies or foster or strengthen marriage, the household's gross income must be under 200 percent of poverty. However, if the purpose of the program is to assist needy families and reduce their dependency, no additional SNAP means test is required beyond that already used for the TANF/Maintenance of Effort program.

Many States have broad programs that provide a TANF/Maintenance of Effort–funded noncash benefit to confer categorical eligibility for SNAP on a large number of households. These policies are known as broad-based categorical eligibility policies. States have flexibility in setting the criteria for receiving the TANF/Maintenance of Effort–funded noncash benefit. States often apply only a gross income eligibility limit—between 130 and 200 percent of federal poverty guidelines—and have eliminated the net income test, although participants must still qualify for a benefit. Most categorically eligible households are not subject to the SNAP resource test. In fiscal year 2014, five States (Idaho, Michigan, Nebraska, Pennsylvania, and Texas) had resource limits between \$5,000 and \$25,000 when determining eligibility.

The number of States and territories (including the District of Columbia, Guam, and the Virgin Islands) implementing broad-based categorical eligibility policies remained at 43 in fiscal years 2012 and 2013, and for the majority of fiscal year 2014. In August 2014, Louisiana abolished its broad-based categorical eligibility policy. Of the 42 States with a broad-based categorical eligibility policy in

[4] The Secretary of the U.S. Department of Health and Human Services (HHS) establishes the federal poverty guidelines annually for many assistance programs. See Appendix C for a list of the 2013 poverty guidelines.

effect throughout fiscal year 2014, New Hampshire is the only State whose policy applies exclusively to households with children.

In some States, households that participate in more narrowly targeted, noncash TANF-funded programs, such as work support, child care, diversion assistance, transportation, and other short-term assistance, may also be categorically eligible for SNAP.

Income Eligibility Standards

Monthly income is the most important determinant of a household's SNAP eligibility. Most households not categorically eligible must meet two income eligibility standards: (1) a gross income standard and (2) a net income standard.[5] As defined in the Food and Nutrition Act of 2008, as amended, gross income includes most cash income (with the exception of specific types of income, such as loans) and excludes most noncash income or in-kind benefits (such as energy assistance payments and educational loans in which payment is deferred). To be eligible for SNAP, a household not categorically eligible and not including an elderly member or individual with a disability must have a monthly gross income that is at or below 130 percent of the federal poverty guideline ($2,552 per month for a family of four in the contiguous United States in fiscal year 2014). Households with elderly members or individuals with disabilities are not subject to the gross income standard. All households that are not categorically eligible must have a monthly net income at or below 100 percent of the poverty guideline ($1,963 for a family of four in the contiguous United States in fiscal year 2014). The gross and net income eligibility standards vary by household size and for residents of Alaska and Hawaii (Appendix C).

In addition to being used to determine income eligibility for some households, net income is used to determine monthly SNAP benefit amounts for all households. Net income is calculated by subtracting deductions permitted under SNAP from monthly gross income. SNAP deducts the following from a household's gross monthly income to arrive at net monthly income:[6]

- **Standard deduction.** Households receive a standard deduction based on location and household size. In fiscal year 2014, a household with one to three members living in the contiguous United States received a $152 deduction; larger households received a larger standard deduction based on household size. The standard deductions for outlying States and territories vary with price differences between such areas and the contiguous United States (Appendix C). The standard deductions are indexed annually to inflation.
- **Earned income deduction.** Households with earnings receive a deduction equal to 20 percent of the combined earnings of household members.
- **Dependent care deduction.** Households with dependents receive a deduction for out-of-pocket costs for the care of children and other dependents while other household members work, seek employment, or attend school.

[5] Individuals participating in the Minnesota Family Investment Program (MFIP) or an SSI Combined Application Project (SSI-CAP) are subject to different eligibility and benefit determination rules, as described later in this chapter.

[6] The amount of deductions to which a household is entitled—the household's deduction entitlement—is not always equal to the amount used to compute SNAP benefits. Because net income may not be less than zero, households with total deductions greater than their gross income may claim only a portion of their deduction entitlement.

- **Medical deduction.** Households receive a medical expense deduction if they have either an elderly member or an individual with a disability who has medical expenses. In most States, such households may deduct combined out-of-pocket medical costs that exceed $35 per month and are incurred on behalf of elderly household members or household members with disabilities. In fiscal year 2014, 15 States had medical deduction demonstration programs that used standard deduction amounts for households with medical expenses exceeding $35 but below a specified limit.[7] Medical expenses reimbursed by insurance or government programs are not deductible in any State.

- **Child support payment deduction.** Households may deduct legally obligated child support payments made to or for a non-household member. States may choose to exclude child support payments from gross income rather than treat them as a deduction.

- **Excess shelter expense deduction.** Households are entitled to a deduction equal to shelter costs (such as rent, mortgage payments, utility bills, property taxes, and insurance) that exceed 50 percent of the household's countable income after all other potential deductions are subtracted from gross income. Instead of using actual utility costs, many States use Standard Utility Allowances (SUAs) to calculate a household's total shelter expense. The maximum excess shelter expense deduction in the contiguous United States for households without elderly members or individuals with disabilities was $478 in fiscal year 2014. The amount is annually indexed to inflation. The limits on the excess shelter expense deduction for outlying States and territories vary with price differences between such areas and the contiguous United States (Appendix C). Households with elderly members or individuals with disabilities are allowed to subtract the full value of shelter costs that exceed 50 percent of their adjusted income. Some States also allow homeless households a deduction of $143 for shelter costs.

Resources

Another determinant of SNAP eligibility is a household's resources. As stipulated in the Food and Nutrition Act of 2008, as amended, the resource limits are indexed to inflation, rounded down to the nearest $250 increment. In fiscal year 2014, households not categorically eligible were permitted up to $2,000 in countable resources or up to $3,250 if at least one household member was elderly or had a disability. Countable resources include cash, resources easily converted to cash (such as money in checking or savings accounts, savings certificates, stocks and bonds, and lump-sum payments), and some nonliquid resources. However, some types of resources are not counted, such as retirement and educational savings accounts, family homes, tools of a trade, or business property used to earn income.

Vehicles with equity below $1,500 are excluded from the resource test. Vehicles used as homes, to produce earned income, to transport household members with physical disabilities, or to transport fuel or water are also excluded. Otherwise, for one vehicle per adult and any vehicle used by a teenager in the household to drive to work or school, any fair market value in excess of $4,650 is counted toward the resource limit. Of the household's remaining vehicles, the higher of (1) any fair market value in excess of $4,650 or (2) any equity is counted.[8]

[7] For detailed information on these demonstrations, see *Technical Documentation for the Fiscal Year 2014 SNAP QC Database and QC Minimodel* (Vigil, Farson Gray, Kochhar, and Schechter, 2015). https://host76.mathematica-mpr.com/fns/.

[8] The equity of a vehicle is defined as its fair market value minus remaining liens.

States are allowed to align their SNAP vehicle policy with TANF vehicle rules so long as the State's TANF rules are less restrictive than federal rules. In fiscal year 2014, all but five States or territories (Delaware, Minnesota, North Dakota, Virgin Islands, and Washington) had aligned their vehicle rules for non-categorically eligible households with those of other programs in their State or territory; 29 States had adopted rules that exclude all vehicles from the resource test. These changes were intended to make it easier for low-income workers to keep a vehicle and still receive SNAP benefits.

Nonfinancial Eligibility Standards

The program's nonfinancial eligibility standards restrict the participation of strikers, individuals who are institutionalized, fleeing felons, drug felons, unauthorized immigrants, nonimmigrant visitors to the United States, certain students, and some lawful permanent resident noncitizens.

The following groups of lawful permanent resident noncitizens are eligible for SNAP benefits:

- Those who have lived legally in the United States for five years or more from the date of entry
- Children under age 18
- Blind or disabled individuals receiving government benefits for their condition
- Noncitizens who are members of the U.S. Armed Forces, veterans, or dependents of a service member or veteran
- Lawful permanent residents with 40 qualifying quarters of work history
- Individuals who were age 65 or older and lawfully resided in the United States on August 22, 1996
- Individuals who were age 65 or older and lawfully resided in the United States on August 22, 1996
- Individuals admitted as refugees or granted asylum or a stay of deportation

Many SNAP participants age 16 to 59 are subject to the program's general work requirements, which include registering for work, accepting suitable employment if offered, not voluntarily quitting a job or reducing work hours, and participating in an employment and training program if referred to one by the State agency. Working age participants are subject to these requirements unless they are in one of the following exempt groups:

- Individuals determined to be mentally or physically unfit for employment
- Individuals employed 30 or more hours per week
- Individuals responsible for the care of a dependent child under age 6 or an incapacitated person
- Students enrolled at least half-time in a school, training program, or institution of higher education
- Individuals complying with work requirements of TANF assistance programs
- Individuals receiving unemployment compensation
- Individuals participating in a drug addiction or alcohol treatment program

In addition, SNAP participants who are subject to the general SNAP work requirements and are (1) age 18 to 49, (2) residing in a SNAP household without children and (3) not pregnant are generally subject to time limited participation unless they fulfill additional work requirements. Specifically, these individuals are restricted to three months of SNAP benefits in any 36-month period unless they work or participate in a work program at least 20 hours per week, or participate in a workfare program. Participants are exempt from the time limit if they live in a waiver area or have been granted a discretionary exemption by the State. States may apply for geographic areas, including the entire State if applicable, to be waiver areas if (1) the area has an unemployment rate that exceeds 10 percent, or (2) the State can demonstrate using other economic criteria that the proposed waiver area has an insufficient number of jobs to provide employment. States are allowed to provide discretionary exemptions for up to 15 percent of their SNAP caseload subject to the time limit.

Application Procedures

When a household applies for SNAP benefits, State agencies are required to conduct an interview at initial certification and at least once every 12 months thereafter. Although all SNAP applicants have the option to appear in person for the interview, most States have waivers that allow interviews to be conducted by telephone or online rather than face-to-face. As of September 2014, 46 States had been granted statewide waivers for the requirement that households receive a face-to-face interview. Thirteen of these States provide the option of a telephone interview at initial certification only, one State offers this option only at recertification, and 32 States provide the option of a telephone interview at both initial certification and recertification. Households for which it would be a hardship to attend an in-person interview, such as those consisting of an elderly individual or an individual with a disability, may be interviewed by telephone or at home regardless of whether the State has a waiver of the face-to-face requirement. Also, as of September 2014, 41 States offered statewide online applications. All States must allow individuals to apply for SNAP benefits when they apply for TANF or SSI benefits.

The Food and Nutrition Act of 2008, as amended, requires local offices to process applications for SNAP benefits within 30 days of receipt. However, applications from households with extremely low income or a low level of resources must be processed more quickly under the expedited SNAP eligibility verification procedures, allowing people to receive SNAP benefits within seven days of application. Those eligible for expedited service include (1) migrant or seasonal farm workers with countable resources equal to or less than $100, (2) households with gross income equal to or less than $150 and countable resources equal to or less than $100, and (3) households whose combined monthly gross income and liquid resources are less than the household's monthly rent or mortgage plus utilities.

SNAP participants are required to appear periodically at their local SNAP office or participate in a telephone interview for recertification. The certification period varies with the likelihood of a change in a SNAP household's financial circumstances. The certification period may be as long as 24 months for households where all members are elderly or disabled, up to 36 months for households participating in an Elderly Simplified Application Project, and up to 48 months for households participating in SSI-Combined Application Project (SSI-CAP) demonstrations. In fiscal year 2014, SNAP households were certified for benefits for an average of 13 months.

Benefit Computation

After a household is certified for SNAP, its monthly SNAP benefit is computed on the basis of its net monthly income, the benefit reduction rate, and the maximum SNAP benefit for the household size and location. The maximum benefit to which a household is entitled has been historically based on 100 percent of the cost of the Thrifty Food Plan for a family of four in June of the previous fiscal year, adjusted for household size and for geographic areas outside of the contiguous United States. The Thrifty Food Plan is a healthful and minimal-cost diet, with the cost adjusted for household size and composition.[9] Maximum benefits are usually revised annually to reflect changes in the cost of foods in the plan.

As specified in the American Recovery and Reinvestment Act of 2009 (ARRA), maximum benefits were set to 113.6 percent of the June 2008 Thrifty Food Plan beginning in April 2009. When the ARRA provision expired on October 31, 2013, maximum benefits returned to 100 percent of the Thrifty Food Plan in the preceding June. Given the expiration of this legislation, there were two sets of maximum benefit levels for fiscal year 2014. The maximum monthly benefit for a family of four in the contiguous United States was $668 in October 2013 and $632 from November 2013 through September 2014 (Appendix C).

Participant households are expected to spend about 30 percent of their net cash income on food, with SNAP benefits providing the difference between that amount and the maximum benefit. Given that assumption, SNAP benefits are calculated by subtracting 30 percent of a household's net income from the maximum benefit amount to which it is entitled. This 30 percent rate, at which benefits are reduced for every additional dollar of net income, is called the benefit reduction rate.

If a household has zero net income (that is, its deductible expenses equal or exceed its gross income), it receives the maximum SNAP benefit. For new participants, benefits are prorated for the first month.[10] All eligible one- and two-person households are guaranteed a minimum benefit, except during the initial month of participation. The minimum benefit for one- and two-person households is 8 percent of the maximum benefit for a one-person household. In fiscal year 2014, the minimum benefit for one- and two-person households in the contiguous United States was $16 in October 2013 and $15 from November 2013 through September 2014.[11]

SSI Combined Application Project (SSI-CAP) Households

Certain households with SSI benefits participate in SNAP through SSI Combined Application Project (SSI-CAP) demonstrations. SSI-CAP is a joint project of FNS, the Social Security Administration (SSA), and States that streamlines the SNAP application process for certain households eligible for SSI (also making them categorically eligible for SNAP). SSI-CAP eligibility rules and the computation of SNAP benefits for SSI-CAP households are different from other households. Throughout fiscal year 2014, 18 States were operating SSI-CAP demonstrations: Arizona,

[9] See Thrifty Food Plan reports at http://www.cnpp.usda.gov/USDAFoodPlansCostofFood/reports for more information.

[10] SNAP households will not receive benefits in the first month if the amount of prorated benefits would be less than $10.

[11] Table C.6 presents minimum benefit values for the other States and territories for fiscal year 2014.

Florida, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, New Jersey, New Mexico, New York, North Carolina, Pennsylvania, South Carolina, South Dakota, Texas, Virginia, and Washington.[12] In most cases, SSI-CAP participation was limited to one-person households consisting of an elderly individual or an individual with a disability who receives SSI and has no earned income.[13] In all SSI-CAP States except for Florida, Massachusetts, and Washington, SSI-CAP households receive a standard SNAP benefit based on whether the State categorizes them as having "high" or "low" shelter expenses, as determined by the State. SSI-CAP households in Florida, Massachusetts, and Washington receive a SNAP benefit based on gross income, the standard deduction, a standard utility allowance, and a standardized "high" or "low" shelter expense deduction. SSI-CAP households do not receive any other income deductions.

Minnesota Family Investment Program Households (MFIP)

Under the Minnesota Family Investment Program (MFIP), Minnesota conducts a different benefit computation method for some households that receive TANF and SNAP. The SNAP benefit for MFIP participants is calculated at the same time as the cash assistance benefit by subtracting total income from an income threshold that is based on family size and is higher for families with earnings. If the difference between total income and the threshold is greater than the maximum benefit set by Minnesota, the family receives the full food portion of its benefit and, possibly, an additional cash benefit. As a family's income rises, the cash portion of the benefit is reduced before the food portion is reduced. Families with income closer to the income threshold may not receive a cash benefit and may receive a smaller food benefit as well. MFIP participants are credited with an earnings deduction but are not subject to other income deductions. The earnings deduction rate for MFIP participants was 40 percent in October 2013 and 43 percent from November 2013 through September 2014.

SNAP Benefit Issuance

As in previous years, all 50 States, the District of Columbia, Guam, and the Virgin Islands issued benefits through EBT cards. Households receive an EBT card, similar to a debit card, that is used to purchase food at authorized retail stores. A household's monthly benefit is automatically added to the household account balance each month, and purchases are debited from their account at the time of the transaction.

Program Changes Since the Previous Fiscal Year

During fiscal year 2014, California and the Virgin Islands expanded their broad-based categorical eligibility policies by increasing the gross income limits for households without elderly members or individuals with disabilities. California increased the gross income limit to 200 percent of the federal poverty guideline beginning in July 2014. In October 2013, the Virgin Islands increased their gross income limit to 175 percent of the federal poverty guideline. Louisiana was the only State in fiscal year 2014 to eliminate its broad-based categorical eligibility policy, which it did as of September 2014.

[12] New Mexico ended its SSI-CAP demonstration in March 2014.

[13] In Florida, Massachusetts, and Washington, a household must have no earned income to enter the program but, once enrolled, may have earned income for up to three months and remain eligible. In Kentucky, New York, North Carolina, South Dakota, and Texas, a household with earned income may still be eligible for SSI-CAP benefits. In Kentucky, New Mexico, and South Dakota, married couples may also be eligible for SSI-CAP benefits but each spouse must be approved to receive SSI in order to meet the eligibility requirements and be treated as a member of the same household; in Texas, married couples may participate but are treated as separate households.

In addition, Idaho implemented a medical deduction demonstration program in fiscal year 2014 that uses a standard deduction amount for households with medical expenses below a specified limit. The demonstration program simplifies the application process for qualifying households and may slightly increase eligibility and benefit amounts.

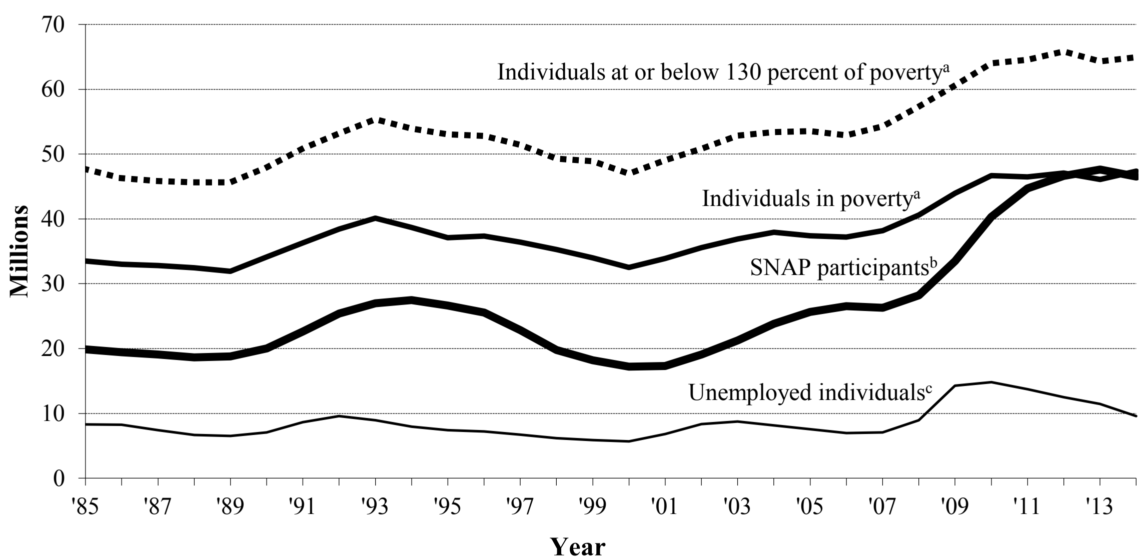
As described earlier, the ARRA increase to maximum SNAP benefits expired in October 2013. In November 2013, maximum SNAP benefits returned to being based on 100 percent of the cost of the Thrifty Food Plan (Appendix C). In addition, the 2014 Farm Bill reauthorized SNAP on February 7, 2014, maintaining the basic eligibility guidelines established under the 2008 Farm Bill. The 2014 Farm Bill also requires that households qualifying for an SUA on the basis of Low Income Heating Assistance Program (LIHEAP) benefits receive a LIHEAP payment greater than $20.

SNAP Participation and Costs

The number of SNAP participants has fluctuated over the past few decades, as illustrated in Figure 2.1. After a decline in SNAP participation from 1994 to 2000, SNAP participation rose steadily each year from 2001 until 2013. The increase in monthly SNAP participation during the economic recession and initial recovery was much greater than in the earlier years, rising from 26.3 million individuals in 2007 to 47.6 million individuals in 2013. There was a slight decline in SNAP participation from 47.6 million individuals in fiscal year 2013 to 46.5 million individuals in fiscal year 2014. Table 2.1 shows how changes in SNAP participation over the last 16 years compare to changes in major economic indicators.

Total SNAP costs declined from $79.9 billion in fiscal year 2013 to $74.2 billion in fiscal year 2014, largely as a result of the decline in SNAP participation.

Figure 2.1. SNAP participants, unemployed individuals, individuals in poverty, and individuals at or below 130 percent of poverty, calendar years 1985 to 2014



[a]Annual values. Source: Special tabulations of the Current Population Survey Annual Social and Economic Supplement (CPS ASEC) by Decision Demographics, Arlington, VA.

[b]Average monthly values. Source: Food and Nutrition Service Fiscal Year Program Operations data.

[c]Average monthly values. Source: Department of Labor, Bureau of Labor Statistics.

Table 2.1. Major economic indicators, calendar years 1999 to 2014

	Calendar year															
Economic indicator	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Inflation rate[a]	1.4	2.3	2.3	1.5	2.0	2.7	3.2	3.1	2.7	1.9	0.8	1.2	2.1	1.8	1.5	1.5
Interest rate[b]	7.1	7.6	7.1	6.5	5.7	5.6	5.2	5.6	5.6	5.6	5.3	4.9	4.6	3.7	4.2	4.2
Productivity increase[c]	3.5	3.4	2.8	4.3	3.8	3.2	2.1	1.0	1.5	0.8	3.3	3.3	0.1	0.9	1.2	0.5
Real GDP increase[d,e]	4.7	4.1	1.0	1.8	2.8	3.8	3.3	2.7	1.8	-0.3	-2.8	2.5	1.6	2.3	2.2	2.4
SNAP participants[f] (000s)	18,183	17,194	17,318	19,096	21,250	23,811	25,628	26,549	26,316	28,223	33,490	40,302	44,709	46,609	47,636	46,537
Unemployed individuals[f] (000s)	5,879	5,685	6,830	8,375	8,770	8,140	7,579	6,991	7,073	8,948	14,295	14,808	13,737	12,498	11,455	9,596
Unemployment rate[g]	4.2	4.0	4.7	5.8	6.0	5.5	5.1	4.6	4.6	5.8	9.3	9.6	8.9	8.1	7.4	6.2
Individuals below poverty level																
Number in thousands	34,005	32,491	33,905	35,566	36,927	37,937	37,415	37,206	38,205	40,614	43,970	46,677	46,464	47,085	46,106	47,348
Percentage of total population	12.3	11.6	12.0	12.4	12.8	13.0	12.7	12.5	12.8	13.5	14.5	15.2	15.0	15.1	14.7	15.0
Individuals at or below 130 percent of poverty level																
Number in thousands	48,905	46,974	49,061	50,844	52,823	53,413	53,553	52,878	54,264	57,329	60,574	63,984	64,549	65,828	64,310	64,915
Percentage of total population	17.7	16.8	17.4	17.8	18.3	18.3	18.2	17.8	18.1	19.0	19.9	20.9	20.9	21.2	20.5	20.5

Sources: Inflation rate: Department of Commerce, Bureau of Economic Analysis, *National Income and Product Accounts.* Interest rate: Board of Governors of the Federal Reserve System. Productivity increase: Department of Labor, Bureau of Labor Statistics, "Major Sector Productivity and Costs Index." Real gross domestic product (GDP) increase: Department of Commerce, Bureau of Economic Analysis, *National Income and Product Accounts.* SNAP participants: Food and Nutrition Service Program Operations data. Unemployed individuals and unemployment rate: Department of Labor, Bureau of Labor Statistics. Individuals below poverty level and individuals at or below 130 percent of poverty level: Special tabulations of the CPS ASEC by Decision Demographics, Arlington, VA.

Note: The calendar year 2013 estimates for individuals below poverty and individuals at or below 130 percent of poverty were updated in this report. The current estimates are based on the full 2014 CPS ASEC, which was not available when the previous report was published.

[a]Percentage change from preceding year in the implicit price deflator for GDP.

[b]Corporate AAA bond yield.

[c]Percentage change from preceding year in output per hour, nonfarm business sector.

[d]Percentage change from preceding year.

[e]The Bureau of Economic Analysis periodically revises GDP estimates. Thus, historical numbers in this table may differ from previous reports.

[f]Average monthly value.

[g]Unemployment rate for all civilian workers.

CHAPTER 3: CHARACTERISTICS OF SNAP HOUSEHOLDS AND PARTICIPANTS

SNAP serves the nutritional needs of a broad spectrum of low-income Americans.[14] In an average month in fiscal year 2014, SNAP provided benefits to 45.9 million people living in 22.4 million households.[15] The vast majority of SNAP households (84 percent) lived in poverty, according to the federal poverty guidelines for program eligibility in fiscal year 2014. Most SNAP households (76 percent) included a child (under age 18), an elderly individual (age 60 or older), or a non-elderly individual with a disability. The average SNAP household received a monthly benefit of $253, had gross monthly income of $759, and net monthly income of $335.[16] The average household size was 2.0 people.

In this chapter, we discuss the composition and economic status of SNAP households, characteristics of SNAP participants, and changes in the characteristics of SNAP households from fiscal year 2013 to fiscal year 2014. Table 3.1 and Figure 3.1 show the poverty status of participants and the effect of SNAP benefits on poverty among participating households; Tables 3.2 through 3.4 present sources of income and average monthly income, benefit, and unit size by household composition; Table 3.5 depicts the demographic characteristics of participants; and Table 3.6 compares the change (in constant 2014 dollars) since 2013 in average income, deductions, and benefits for participating households.

The Poverty Status of SNAP Households

SNAP provides benefits to households in need.[17] In fiscal year 2014, the gross monthly income of 84 percent of SNAP households was less than or equal to 100 percent of the federal poverty guideline (Table 3.1).[18] The gross monthly income of 61 percent of all SNAP households was less than or equal to 75 percent of the poverty guideline, and the income of 43 percent of all SNAP households was less than or equal to 50 percent of the guideline (Table 3.1). The average household had income that was slightly less than 58 percent of the poverty guideline (Table A.2).

[14] The information in this chapter and the estimates in Appendices A and B are based on a sample of 48,250 households that participated in SNAP in fiscal year 2014 (see Appendix Table D.2). The sample was drawn from SNAP households in the 50 States, the District of Columbia, Guam, and the U.S. Virgin Islands. Households in Puerto Rico and the Northern Mariana Islands were not included in the sample because both territories receive block grants in lieu of SNAP.

[15] The estimates of 45.9 million participants and 22.4 million households differ slightly from the number of SNAP participants and households in FNS administrative records (46.5 million people and 22.7 million households) because the sample estimate is adjusted to exclude receipt of benefits by ineligible households and those receiving disaster assistance. These adjustments also affect household average monthly benefits, which are $253 in the SNAP QC data compared with $257 in FNS administrative records (Appendix D provides details).

[16] Because net income is not used in benefit determination for households participating in MFIP and for those participating in SSI-CAP with a standardized benefit, the average monthly net income estimate excludes these households.

[17] For more detailed information on the economic status of SNAP households, see Appendix Tables A.3 through A.8.

[18] See Appendix Table C.1 for the poverty guidelines.

SNAP effectively targets benefits to the neediest households; poorer households receive greater SNAP benefits than those with more income. The 43 percent of all SNAP households with gross monthly income less than or equal to 50 percent of the poverty guideline in fiscal year 2014 received 58 percent of all benefits. In contrast, the 16 percent of households with a gross monthly income above the poverty guideline received only 7 percent of all benefits (Table 3.1).

The impact of SNAP benefits on a household's purchasing power is estimated by adding the dollar value of the benefits to a household's income and then examining the distribution of households by poverty status.[19] As shown in Figure 3.1, the combination of cash and SNAP benefits yields a substantially different distribution of SNAP households by poverty status. Specifically, when SNAP benefits are included in gross income, the resulting increase in the income of SNAP households was sufficient to move 10 percent of participating households above the poverty guideline. SNAP benefits affected a greater number of the poorest SNAP households, moving 13 percent of participating households above 50 percent of the poverty guideline.

Households with Greater Needs

SNAP effectively serves many households that include vulnerable individuals—children, elderly adults, and individuals with disabilities.[20] In fiscal year 2014, 76 percent of all SNAP households—which contained 87 percent of all participants—included a child, an elderly individual, or a non-elderly individual with a disability. These households received 82 percent of all SNAP benefits (Table A.14).

Households with Children

In an average month in fiscal year 2014, SNAP served approximately 9.8 million households with children, representing 44 percent of all SNAP households. Seventy-three percent of all SNAP households with earnings contained children, while 52 percent of all households with children had earned income (Tables 3.2 and 3.3). Thirteen percent of all households with children received TANF cash benefits and 3 percent received a combination of TANF and earnings (Table A.6). Compared with other SNAP households, those with children received a relatively high average SNAP benefit of $390 per month (Table 3.4), in large part because the household size among SNAP households with children (3.2 people) was larger than the average household size among all SNAP households (2.0 people).

In fiscal year 2014, single adults headed more than half (57 percent) of all SNAP households with children, accounting for 25 percent of all SNAP households (Table 3.2). Eight percent of all SNAP households included a married head of household and children, accounting for 18 percent of all SNAP households with children.

[19] This comparison assumes that program participants value their SNAP benefits at face value.

[20] See Appendix Tables A.3, A.6, A.8, A.11, A.12, A.14–A.19, and A.21–A.23 for more details on these households.

Table 3.1. Distribution of households and their benefits by countable income as a percentage of poverty guideline, fiscal year 2014

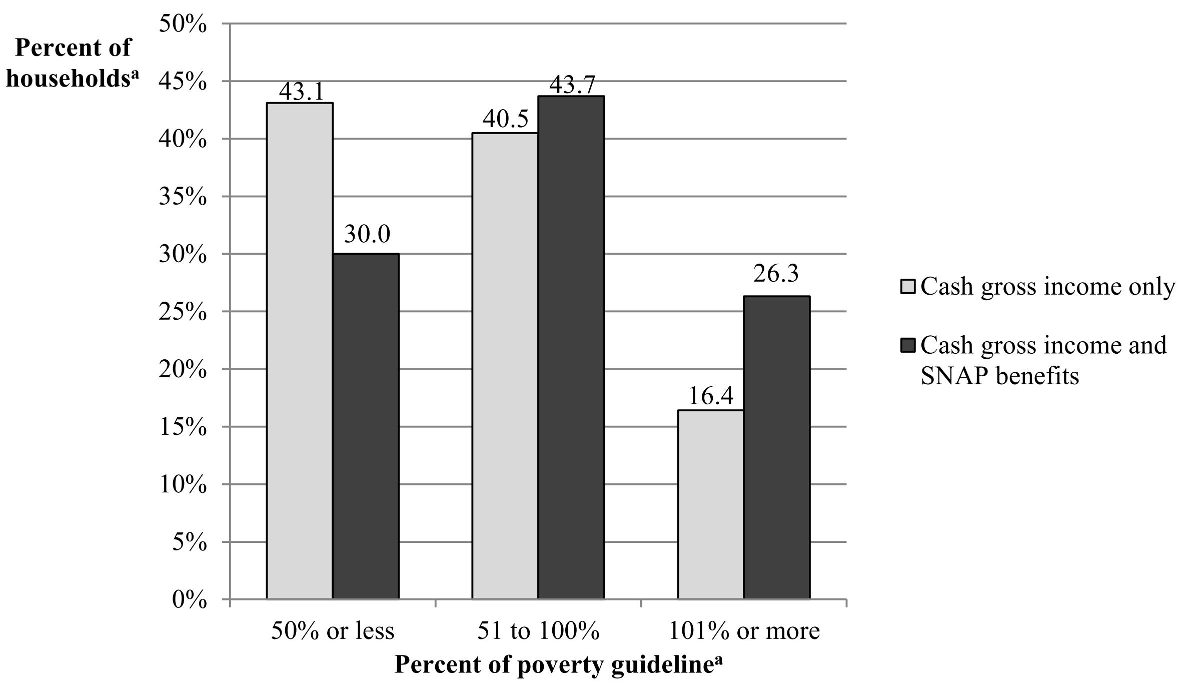
Gross income as a percentage of poverty guideline[a]	All households		All benefits	
	Percentage	Cumulative percentage	Percentage	Cumulative percentage
25% or less	30.6	30.6	37.7	37.7
26 to 50%	12.5	43.1	20.1	57.9
51 to 75%	17.7	60.8	19.2	77.1
76 to 100%	22.8	83.6	15.8	92.9
101 to 130%	11.6	95.2	5.9	98.8
131% or more	4.8	100.0	1.2	100.0

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

Note: Estimates may not sum to 100 percent due to rounding.

[a]Defined as the fiscal year 2014 SNAP net income screen (Appendix Table C.3).

Figure 3.1. Effect of SNAP benefits on the poverty status of SNAP households, fiscal year 2014



Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a]Defined as the fiscal year 2014 SNAP net income screen (Appendix Table C.3).

The characteristics of married-head households with children varied considerably from those of single-adult households with children. Of the 5.6 million single-adult SNAP households with children, 2.3 million (42 percent) had earnings, about 877,000 (16 percent) received TANF, 681,000 (12 percent) received SSI, and 528,000 (9 percent) received Social Security. Of the 1.8 million married-head households with children, 1.2 million (69 percent) had earned income, 185,000 (10 percent) received SSI, 177,000 (10 percent) received Social Security, and 124,000 (7 percent) received TANF. Among single-adult households with children, 963,000 (17 percent) had zero gross income whereas among married-head households, 178,000 (10 percent) had zero gross income (Table 3.3).

The average monthly SNAP benefit for single-adult households with children was lower than that of married-head households with children ($375 versus $454) because of the smaller size of single-adult households (Table 3.4). However, the benefit per person was higher for people in single-adult households with children than for people in married-head households with children ($129 versus $103) because single-adult households were poorer. Single-adult households with children had a substantially lower gross monthly income than married-head households with children ($841 versus $1,426).

Among all households with children, 1.8 million (18 percent) received child support (Table A.6).

Households with Elderly Individuals

In each month of fiscal year 2014, SNAP served an average of about 4.3 million households with elderly individuals (age 60 and older). These households represented 19 percent of all SNAP households, compared to 17 percent of all SNAP households in fiscal year 2013 (Table 3.2). Households with elderly individuals had an average household size of 1.3 people (Table 3.4).

In fiscal year 2014, the average SNAP benefit for households with elderly individuals was $129, compared to $283 for households without elderly individuals (Table A.2). Elderly SNAP recipients tended to receive relatively small benefit amounts for two reasons. First, they typically had higher average gross and net incomes than other households. Households with elderly individuals had average gross and net incomes of $876 and $407, compared to $732 and $319 for households without elderly individuals. Second, elderly SNAP recipients often lived alone and thus were eligible for smaller maximum benefit amounts than other households.[21]

In fiscal year 2014, 82 percent of all SNAP households with elderly individuals were single-person households (Table 3.2). Elderly SNAP recipients who lived alone received an average SNAP benefit of $110 per month, compared to $160 for multiperson households composed of only elderly individuals and $256 for multiperson households with both elderly and non-elderly individuals (Table A.15). The average size of households with elderly individuals not living alone was 2.4 people (Table 3.4).

A majority of SNAP households with elderly individuals received either SSI or Social Security income. In fiscal year 2014, 37 percent of all SNAP households with elderly individuals received SSI, 69 percent received Social Security income, and 85 percent received income from at least one of those two sources (Table A.6).

[21] In this report, we use the term "living alone" to refer to individuals who reside in one-person SNAP households, although others may live in the same residential unit.

Table 3.2. Household receipt of countable income types by household composition, fiscal year 2014

Households with:	All households		Households with countable:											
			Earned income		Social Security		SSI		Zero gross income		TANF		GA	
	Number (000)	Column percent	Number (000)	Column percent	Number (000)	Column percent	Number (000)	Column percent	Number (000)	Column percent	Number (000)	Column percent	Number (000)	Column percent
Total[a]	22,445	100.0	7,016	100.0	5,505	100.0	4,568	100.0	4,919	100.0	1,362	100.0	694	100.0
Children	9,789	43.6	5,113	72.9	871	15.8	1,125	24.6	1,376	28.0	1,313	96.4	142	20.5
Single-adult household	5,591	24.9	2,327	33.2	528	9.6	681	14.9	963	19.6	877	64.4	92	13.2
Multiple-adult household	2,834	12.6	1,817	25.9	332	6.0	385	8.4	285	5.8	247	18.1	33	4.8
Married-head household	1,788	8.0	1,236	17.6	177	3.2	185	4.1	178	3.6	124	9.1	18	2.6
Other multiple-adult household	1,047	4.7	581	8.3	154	2.8	200	4.4	107	2.2	123	9.0	15	2.2
Children only	1,363	6.1	969	13.8	11	0.2	60	1.3	128	2.6	188	13.8	18	2.5
Elderly individuals	4,255	19.0	291	4.2	2,914	52.9	1,556	34.1	308	6.3	37	2.7	159	22.9
Living alone	3,473	15.5	162	2.3	2,379	43.2	1,263	27.6	288	5.8	1	0.1	127	18.3
Not living alone	782	3.5	130	1.8	536	9.7	293	6.4	20	0.4	35	2.6	32	4.6
Non-elderly individuals with disabilities	4,579	20.4	518	7.4	2,354	42.8	3,101	67.9	0	0.0	245	18.0	152	22.0
Living alone	2,760	12.3	144	2.1	1,561	28.4	1,734	37.9	0	0.0	2	0.1	79	11.4
Not living alone	1,819	8.1	373	5.3	793	14.4	1,367	29.9	–	–	244	17.9	73	10.5
Other households[b]	5,475	24.4	1,448	20.6	60	1.1	0	0.0	3,239	65.8	42	3.1	304	43.8
Single-person household	5,028	22.4	1,208	17.2	44	0.8	0	0.0	3,107	63.2	32	2.3	288	41.5
Multiperson household	447	2.0	240	3.4	16	0.3	–	–	131	2.7	10	0.7	16	2.4
Single-person households	11,670	52.0	1,779	25.4	3,989	72.5	2,998	65.6	3,447	70.1	99	7.3	504	72.6

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] The sums of the household types do not match the numbers in the Total row because a household may have more than one of the characteristics.

[b] Households not containing children, elderly individuals, or non-elderly individuals with disabilities.

– No sample households are in this category.

Table 3.3. Percentage of households with countable income types by household composition, fiscal year 2014

Households with:	All households		Households with countable:											
			Earned income		Social Security		SSI		Zero gross income		TANF		GA	
	Number (000)	Percent	Number (000)	Row percent	Number (000)	Row percent	Number (000)	Row percent	Number (000)	Row percent	Number (000)	Row percent	Number (000)	Row percent
Total[a]	22,445	100.0	7,016	31.3	5,505	24.5	4,568	20.4	4,919	21.9	1,362	6.1	694	3.1
Children	9,789	43.6	5,113	52.2	871	8.9	1,125	11.5	1,376	14.1	1,313	13.4	142	1.5
Single-adult household	5,591	24.9	2,327	41.6	528	9.4	681	12.2	963	17.2	877	15.7	92	1.6
Multiple-adult household	2,834	12.6	1,817	64.1	332	11.7	385	13.6	285	10.1	247	8.7	33	1.2
Married-head household	1,788	8.0	1,236	69.1	177	9.9	185	10.4	178	10.0	124	6.9	18	1.0
Other multiple-adult household	1,047	4.7	581	55.5	154	14.7	200	19.1	107	10.3	123	11.7	15	1.5
Children only	1,363	6.1	969	71.1	11	0.8	60	4.4	128	9.4	188	13.8	18	1.3
Elderly individuals	4,255	19.0	291	6.8	2,914	68.5	1,556	36.6	308	7.2	37	0.9	159	3.7
Living alone	3,473	15.5	162	4.7	2,379	68.5	1,263	36.4	288	8.3	1	0.0	127	3.7
Not living alone	782	3.5	130	16.6	536	68.5	293	37.5	20	2.6	35	4.5	32	4.1
Non-elderly individuals with disabilities	4,579	20.4	518	11.3	2,354	51.4	3,101	67.7	0	0.0	245	5.4	152	3.3
Living alone	2,760	12.3	144	5.2	1,561	56.6	1,734	62.8	0	0.0	2	0.1	79	2.9
Not living alone	1,819	8.1	373	20.5	793	43.6	1,367	75.2	–	–	244	13.4	73	4.0
Other households[b]	5,475	24.4	1,448	26.5	60	1.1	0	0.0	3,239	59.2	42	0.8	304	5.6
Single-person household	5,028	22.4	1,208	24.0	44	0.9	0	0.0	3,107	61.8	32	0.6	288	5.7
Multiperson household	447	2.0	240	53.6	16	3.6	–	–	131	29.4	10	2.3	16	3.7
Single-person households	11,670	52.0	1,779	15.2	3,989	34.2	2,998	25.7	3,447	29.5	99	0.8	504	4.3

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] The sums of the household types do not match the numbers in the Total row because a household may have more than one of the characteristics.

[b] Households not containing children, elderly individuals, or non-elderly individuals with disabilities.

– No sample households are in this category.

Table 3.4. Average values of selected characteristics by household composition, fiscal year 2014

Households with:	Average values				
	Gross monthly countable income (dollars)	Net monthly countable income (dollars)[a]	Monthly SNAP benefit (dollars)	Monthly SNAP benefit per person (dollars)[b]	Household size (individuals)
Total	759	335	253	126	2.0
Children	965	449	390	122	3.2
Single-adult household	841	373	375	129	2.9
Male adult	765	319	349	134	2.6
Female adult	847	378	377	126	3.0
Multiple-adult household	1,336	715	457	106	4.3
Married-head household	1,426	768	454	103	4.4
Other multiple-adult household	1,184	624	463	113	4.1
Children only	706	207	315	143	2.2
Elderly individuals	876	407	129	99	1.3
Living alone	791	332	110	110	1.0
Not living alone	1,253	708	212	88	2.4
Non-elderly individuals with disabilities	1,006	501	187	98	1.9
Living alone	828	322	108	108	1.0
Not living alone	1,277	746	308	93	3.3
Other households[c]	259	83	185	168	1.1
Single-person household	221	66	174	174	1.0
Multiperson household	687	271	304	138	2.2
Single-person households	542	199	140	140	1.0

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Because net income is not used in their benefit determinations, 23,481 MFIP households and 565,481 SSI-CAP households in States that use standardized SSI-CAP benefits are excluded from this column.

[b] This column is calculated by dividing the rounded, average monthly SNAP benefit by the rounded, average SNAP household size.

[c] Households not containing children, elderly individuals, or non-elderly individuals with disabilities.

Twenty percent of households with elderly individuals received both SSI and Social Security income (Table A.6). SNAP households with elderly individuals represented 34 percent of all SNAP households with SSI and 53 percent of all SNAP households with Social Security income (Table 3.2). Seven percent of households with elderly individuals had no income (Table A.6).

Households with Non-Elderly Individuals with Disabilities

In fiscal year 2014, SNAP served a monthly average of 4.6 million households with non-elderly individuals with disabilities (Table 3.2).[22] These households represented 20 percent of all SNAP households and received an average monthly SNAP benefit of $187 (Table 3.4).

Sixty percent of SNAP households with non-elderly individuals with disabilities were single-person households (Table 3.2). Non-elderly individuals with disabilities who did not live alone resided in households with an average of 3.3 individuals and a per-person benefit of $93, versus a per-person benefit of $108 for those living alone. Sixty-eight percent of households with non-elderly individuals with disabilities received SSI, and 51 percent received Social Security income (Table 3.3). SNAP households with non-elderly individuals with disabilities represented 68 percent of all SNAP households with SSI and 43 percent of all SNAP households with Social Security income (Table 3.2).

Other Households Served by SNAP

While the majority of SNAP households contained children, elderly individuals, or individuals with disabilities, in fiscal year 2014, 24 percent (5.5 million households) consisted solely of one or more non-elderly adults without disabilities with no children (Table 3.2). These households tended to be single-person households (92 percent) and had a very low average gross monthly income ($259), although about one-fourth (27 percent) had earned income. Fifty-nine percent of these households had zero gross income (Tables 3.3 and 3.4). Households consisting solely of one or more non-elderly adults without disabilities received an average SNAP benefit of $185 per month (Table 3.4).

Single-Person Households

Of all SNAP households in fiscal year 2014, 11.7 million (52 percent) were single-person households (Table 3.2).[23] These households received an average monthly SNAP benefit of $140 (Table 3.4). A slight majority of these individuals (53 percent) were female (Table A.24), 30 percent were elderly (Table A.17), and 24 percent were non-elderly individuals with disabilities (Table A.17). Compared with all SNAP households, a relatively small proportion of SNAP participants living alone had earned income (15 percent versus 31 percent) and a relatively high proportion had zero gross income (30 percent versus 22 percent) (Table 3.3). By comparison, 49 percent of all multiperson households had earned income and 14 percent had zero gross income (Tables A.19 and A.4, calculated by subtracting the number of one-person households from the number of total households). Not surprisingly, given the high proportion of elderly individuals and individuals with disabilities making up single-person households, 34 percent and 26 percent of single-person households received Social Security income and SSI income, respectively (Table 3.3).

[22] We identify households with a non-elderly member with a disability as those with (1) non-elderly SSI recipients, (2) a medical expense deduction and no elderly individuals, or (3) non-elderly adults who work fewer than 30 hours a week and receive Social Security, veterans' benefits, or workers' compensation.

[23] These individuals apply for SNAP benefits for themselves only. Other people may live in the household.

Characteristics of SNAP Participants

In fiscal year 2014, 44 percent of SNAP participants were children, and they received 44 percent of prorated SNAP benefits (Table 3.5). More than two-thirds (69 percent) of children served by SNAP were school age (age 5 to 17). Forty-six percent of participants were non-elderly adults and 10 percent were elderly adults.

Sixty-two percent of non-elderly adults and 63 percent of elderly adults were female (Table A.23). Eight percent of SNAP participants were foreign-born—4 percent were naturalized citizens, fewer than 1 percent were refugees, and 3 percent were other noncitizens (lawful permanent residents and other eligible noncitizens). As in fiscal year 2013, 9 percent of all SNAP participants were citizen children living with noncitizen adults.[24]

In fiscal year 2014, the average SNAP household size was 2.0 individuals. There has been a steady decline in the average household size over the years analyzed in this report. In fiscal year 1989, the average SNAP household was 2.6 individuals (Table A.27).

Changes in the Economic Conditions of SNAP Households

The average household gross income decreased in real dollars from fiscal year 2013 to fiscal year 2014, from $770 to $759, and the average household net income decreased by $15 to $335 during the same period (Table 3.6).

The percentage of households with zero gross income remained at 22 percent from fiscal year 2013 to fiscal year 2014. The percentage of households with zero net income continued its upward trend, and, in fiscal year 2014, was at its highest level (41 percent) among the years analyzed in this report (Table A.26). The percentage of households with earnings remained at 31 percent and that of households with TANF income decreased, by slightly less than half a percentage point, to 6 percent in fiscal year 2014.

The average household benefit decreased in real dollars, from $276 in fiscal year 2013 to $253 in fiscal year 2014, even as net income per household decreased from $350 to $335 (Table 3.6). The decrease in the average household benefit is likely due to the expiration of ARRA in October 2013 and the corresponding decrease in maximum benefit amounts beginning in November 2013.

[24] Some of the noncitizen household members were legal residents of the United States and participated in SNAP with citizen children; others were ineligible because of their immigration status and did not participate.

Table 3.5. SNAP benefits of participants by selected demographic characteristics, fiscal year 2014

Participant characteristic	Total participants		Prorated benefits[a]	
	Number (000)	Percent	Dollars (000)	Percent
Total	45,874	100.0	5,689,647	100.0
Age				
Children	20,271	44.2	2,474,569	43.5
Preschool-age children	6,369	13.9	819,069	14.4
0 to 1	2,407	5.2	316,184	5.6
2 to 4	3,962	8.6	502,884	8.8
School-age children	13,902	30.3	1,655,501	29.1
5 to 7	3,977	8.7	490,896	8.6
8 to 11	4,620	10.1	552,752	9.7
12 to 15	3,722	8.1	429,143	7.5
16 to 17	1,583	3.5	182,710	3.2
Non-elderly adults (18 to 59)	20,952	45.7	2,733,337	48.0
Elderly adults (60 or older)	4,651	10.1	481,674	8.5
Unknown age	0	0.0	67	0.0
Citizenship				
U.S.-born citizen	42,258	92.1	5,229,372	91.9
Naturalized citizen	1,715	3.7	213,921	3.8
Refugee	356	0.8	43,510	0.8
Other noncitizen	1,545	3.4	202,844	3.6
Citizen children living with noncitizens[b]	4,133	9.0	545,167	9.6
Non-elderly individuals with disabilities	5,467	11.9	537,236	9.4
Children with disabilities	1,006	2.2	90,267	1.6
Non-elderly adults with disabilities	4,461	9.7	446,970	7.9
Adults age 18 to 49 without disabilities in childless households[c]	4,721	10.3	775,692	13.6

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Prorated benefits equal the benefits paid to households multiplied by the ratio of participants with selected characteristic to total household size.

[b] Noncitizens may be inside or outside the SNAP household.

[c] With some exceptions, these participants are subject to work requirements and time limits.

Table 3.6. Nominal and real values of selected characteristics, fiscal year 2013 and fiscal year 2014

	Fiscal year 2013 (October 2012-September 2013)		Fiscal year 2014 (October 2013-September 2014)		
Characteristic	Nominal value	Real value (in 2014 dollars)	Nominal value	Percentage change in nominal values	Percentage change in real values
Average gross income[a]					
Per household	$758	$770	$759	+0.1	-1.5
Per person	430	437	442	+2.6	+1.0
Average net income[a]					
Per household	344	350	335	-2.7	-4.2
Per person	177	179	176	-0.1	-1.7
Average total deduction[a]	522	530	538	+3.1	+1.5
Average household benefit[b]	271	276	253	-6.5	-8.1
Maximum household benefit for a family of four[b,c]	668	679	632	-5.4	-7.0
Consumer price index (CPI)					
All items	232.3		236.0	+1.6	
Food at home	233.5		237.4	+1.7	

Sources: CPI-U average values: U.S. Department of Labor, Bureau of Labor Statistics. Nominal values: Fiscal year 2013 and fiscal year 2014 SNAP QC samples.

[a]Real values are in constant 2014 dollars. Fiscal year 2013 values were inflated by the change in the CPI-U for all items between 2013 and 2014 (+1.6 percent).

[b]Real values are in constant 2014 dollars. Fiscal year 2013 value was inflated by the change in the CPI-U for food at home between 2013 and 2014 (+1.0 percent).

[c]Maximum benefit for a family of four living in the 48 contiguous States or the District of Columbia from November 2013 to September 2014. ARRA legislation increased the maximum SNAP benefit to 113.6 percent of the June 2008 Thrifty Food Plan and held it at that level until October 31, 2013. In November 2013, the maximum SNAP benefit returned to being based on 100 percent of the cost of the Thrifty Food Plan of the preceding June.

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ACRONYMS AND DEFINITIONS

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ACRONYMS

ARRA	American Recovery and Reinvestment Act of 2009
BBCE	Broad-based categorical eligibility
CPS ASEC	Current Population Survey Annual Social and Economic Supplement
EBT	Electronic Benefit Transfer
FNS	U.S. Department of Agriculture, Food and Nutrition Service
GA	General Assistance
HHS	U.S. Department of Health and Human Services
MFIP	Minnesota Family Investment Program
PA	Public assistance
SNAP	Supplemental Nutrition Assistance Program
SNAP QC	Supplemental Nutrition Assistance Program Quality Control
SSA	Social Security Administration
SSI	Supplemental Security Income
SSI-CAP	SSI Combined Application Project
SUA	Standard utility allowance
TANF	Temporary Assistance for Needy Families
USDA	U.S. Department of Agriculture

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DEFINITIONS

Agricultural Act of 2014 (2014 Farm Bill). This legislation, which reauthorized SNAP, was enacted on February 7, 2014. The bill maintained the program's basic eligibility guidelines while reducing or eliminating the shelter expense deduction for some households with no energy costs and nominal energy assistance. The bill also provided additional SNAP funding for enhanced employment and training activities, and expanded antifraud efforts.

American Recovery and Reinvestment Act of 2009 (ARRA). This legislation, which took effect on April 1, 2009, temporarily increased the maximum benefit to 113.6 percent of the June 2008 Thrifty Food Plan. As specified in subsequent legislation, this provision expired on October 31, 2013, and the maximum benefit returned to being based on 100 percent of the cost of the Thrifty Food Plan in the preceding June.

Broad-based categorical eligibility (BBCE). Policy under which households receive a TANF/Maintenance of Effort–funded noncash service that makes them categorically eligible for SNAP. The noncash service is usually in the form of a brochure or handout that provides information on State-provided assistance and services. Households meeting State-determined eligibility criteria receive this information upon application or recertification for SNAP.

Categorically eligible households. Households in which all members receive or are authorized to receive TANF, SSI, or GA benefits and therefore are deemed financially eligible for SNAP. Includes households receiving cash or noncash benefits or services that are at least 50 percent funded by TANF or Maintenance of Effort funds. Some States also confer categorical eligibility based on benefits or services that are less than 50 percent funded by TANF/Maintenance of Effort, and on households in which at least one member receives a benefit or service and the State determines that the entire household benefits. If the purpose of the program conferring categorical eligibility is to prevent out-of-wedlock pregnancies or to foster or strengthen marriage, the household's gross income must be under 200 percent of poverty. However, if the purpose of the program is to further workforce participation, this income limit does not apply.

Certification period. Length of time a household is certified to receive SNAP benefits. When the certification period expires, households must be recertified to continue receiving benefits.

Child support payment deduction. Deduction from gross income in the eligibility and benefit calculation for households with legally obligated child support payments made to or for a nonmember of the household. States may choose to exclude child support payments from gross income rather than use the deduction. See also *Deductions*.

Children. Individuals under age 18.

Countable income. All earned or unearned income that is counted toward gross income. This includes most cash income (with the exception of specific types of income, such as loans) and excludes most noncash income or in-kind benefits. See also *Gross income limit*.

Countable resources. Cash on hand and resources that may be converted easily to cash, such as money in checking or savings accounts, savings certificates, stocks or bonds, and lump-sum payments. Such resources also include some nonliquid resources, although the family home, certain family vehicles, and business tools or property are not counted. See also *Resource limit*.

Deductions. Allowable deductions from a household's gross monthly income used to calculate SNAP net monthly income. The deductions shown in the appendix tables are those to which households were entitled. (MFIP and SSI-CAP participants are subject to different rules.) Total deductions to which a household is entitled do not always equal the difference between gross and net income amounts because net income may not be less than zero. See also *Child support payment deduction, Dependent care deduction, Earned income deduction, Excess shelter expense deduction, Medical deduction, MFIP, SSI-CAP, Standard deduction,* and *Total deduction*.

Deemed income. Individual sponsors of certain noncitizens may be subject to sponsor-to-noncitizen deeming, which counts the sponsor's income and resources as part of the noncitizen's income and resources when determining eligibility for SNAP.

Dependent care deduction. Deduction received by SNAP households for expenses involved in caring for dependents while other household members work, seek employment, or attend school. See also Appendix C and *Deductions*.

Earned income. Includes wages, salaries, self-employment, and other reported earned income.

Earned income deduction. Deduction received by households with earnings, equal to 20 percent of the combined earnings of household members. (MFIP participants were entitled to a 40 percent earned income deduction in October 2013 and a 43 percent earned income deduction from November 2013 through September 2014.) See also *Deductions* and *Minnesota Family Investment Program*.

Elderly individuals. Adults age 60 or older.

Electronic Benefit Transfer. Means of benefit delivery via Electronic Benefit Transfer card, similar to a debit card, used to purchase food at authorized retail stores.

Entrant households. Households newly certified during fiscal year 2014 and in their first month of participation.

Excess shelter expense deduction. Deduction received by households with shelter costs, equal to those shelter costs that exceed 50 percent of the household's countable income after all other potential deductions are subtracted from gross income. There is a limit on the shelter deduction for households without elderly members or individuals with disabilities. See also *Deductions, Homeless household shelter estimate,* and Appendix C.

Expedited service households. Households with gross income equal to or less than $150 and countable resources equal to or less than $100 and households with migrant or seasonal farm workers with countable resources equal to or less than $100 are eligible for expedited SNAP eligibility verification procedures. A State agency must review each SNAP application and conduct an eligibility interview within seven days of application submission. Eligible households must receive SNAP benefits within this time frame.

Food and Nutrition Act of 2008. The Food Stamp Act of 1977 was renamed the Food and Nutrition Act of 2008 under the 2008 Farm Bill. The Act, as amended, established uniform national eligibility standards for SNAP.

Food, Conservation and Energy Act of 2008 (2008 Farm Bill). Most SNAP provisions in this legislation, which reauthorized SNAP, became effective on October 1, 2008. SNAP provisions included increases in the minimum benefit for one- and two-person households and to the standard deduction, elimination of the cap on the dependent care deduction, and exclusion of most education and retirement accounts from countable resources when determining SNAP eligibility. It also indexed the resource limits to inflation, rounding down to the nearest $250 increment each fiscal year.

Gross income. Total monthly countable income of a household in dollars, before applying deductions.

Gross income limit. SNAP monthly gross income eligibility standards, determined by household size; equal to 130 percent of federal poverty guidelines. See also Appendix C and *Countable income*.

Homeless household shelter estimate. Some States allow homeless households to deduct $143 for shelter expenses.

Household. Individuals who live in a residential unit and purchase and prepare food together. Additionally, spouses living together, and children under the age of 22 living with their parents must be considered a household, regardless of whether or not they purchase and prepare food together.

Individuals living alone. Individuals who reside in one-person SNAP households (although other nonparticipating individuals may live in the same residence).

Individuals with disabilities. Under SNAP rules, a disabled individual is defined as one who receives federal or State payments for the disabled or blind; receives a disability retirement benefit from a governmental agency; or receives an annuity under the Railroad Retirement Act and is either eligible for Medicare or is considered to be disabled based on SSI rules. A disabled veteran, or a permanently disabled spouse or child of a veteran receiving veterans benefits, is also considered to be disabled for SNAP purposes. In this report, individuals with disabilities are those under the age of 60 and (1) with SSI; (2) working fewer than 30 hours per week, exempt from work registration due to disability, and receiving Social Security, veterans' benefits, or workers' compensation; or (3) in a SNAP household without an elderly person but with a medical deduction and some indication of disability such as work registration status, hours worked, or type of income received.

Initial certification households. Includes both households certified for the first time within the current certification period and previously certified households that have not received benefits for at least 30 days.

Lawful permanent residents. Noncitizens lawfully admitted for permanent resident status.

Married-head households. Households with a spouse present or head of household in unit with spouse outside of unit.

Maximum benefit. SNAP benefits are calculated by subtracting 30 percent of a household's net income from the maximum possible benefit amount to which it is entitled based on household size. Historically, the maximum benefit has been based on 100 percent of the cost of the Thrifty Food Plan. From April 2009 through October 2013, the maximum benefit was based on 113.6 percent of the cost of the Thrifty Food Plan in June 2008 for a reference family of four, rounded to the lowest dollar increment. This provision expired on October 31, 2013, and the maximum benefit returned to being based on 100 percent of the cost of the Thrifty Food Plan in the preceding June. The maximum benefit is uniform throughout the contiguous United States but is different for Hawaii, Alaska, the Virgin Islands, and Guam. See also Appendix C.

Medical deduction. Deduction available to households with elderly members or individuals with disabilities, equal to all unreimbursed medical expenses incurred by the elderly individual or individual with a disability that exceed $35. See also *Deductions*.

Medical deduction demonstrations. State programs that use a standard deduction amount for households with medical expenses below a specified limit.

Metropolitan households. Households whose SNAP application was processed at an agency in a Census Bureau-defined Metropolitan Statistical Area (MSA). An MSA has at least one urbanized area with population of 50,000 or more and includes adjacent territory with a high degree of social and economic integration with the core, as measured by commuting ties.

Micropolitan households. Households whose SNAP application was processed at an agency in a Census Bureau-defined Micropolitan Statistical Area. A Micropolitan Statistical Area has at least one urban cluster of at least 10,000 but less than 50,000 in population and includes adjacent territory with a high degree of social and economic integration with the core, as measured by commuting ties.

Minimum benefit. Amount guaranteed to all eligible one- and two-person units except during the initial month of participation. The minimum benefit for all one- and two-person units was equal to 8 percent of the maximum benefit for a one-person household. Because it is derived from the maximum benefit, the minimum benefit also varies by geographic region and month of benefit receipt in fiscal year 2014. See also Appendix C.

Minnesota Family Investment Program (MFIP). Minnesota's cash and food assistance program, which jointly calculates SNAP benefits and cash assistance for participating households.

Net income. Total monthly countable income of a household in dollars, after applying deductions. Net income is not calculated for MFIP households or SSI-CAP households in Arizona, Kentucky, Louisiana, Maryland, Michigan, Mississippi, New Jersey, New Mexico, New York, North Carolina, Pennsylvania, South Carolina, South Dakota, Texas, and Virginia.

Net income limit. SNAP monthly net income eligibility standard, determined by household size, equal to 100 percent of the federal poverty guidelines. See also Appendix C.

Noncitizen. In this report, "noncitizen" refers to individuals residing in the United States who are not natural-born or naturalized citizens. These include lawful permanent residents, refugees, asylees, deportees, and unauthorized aliens. Lawfully present noncitizens are subject to additional nonfinancial eligibility criteria (see Chapter 2). Unauthorized aliens are not eligible to receive SNAP benefits but they may be nonparticipating members of SNAP households.

Non-elderly adults. Adults age 18 to 59.

Nonimmigrant visitors to the United States. Noncitizens who have been admitted for a specified period, including tourists, students, and foreign nationals with work permits.

Nonparticipating household head households. Households headed by someone ineligible for SNAP, such as an ineligible noncitizen.

Other multiple-adult households. Households with unmarried household head, two or more adults, and at least one child.

Other noncitizen. In this report, "other noncitizen" refers to non-refugee, lawful permanent residents in the United States and eligible noncitizens who meet SNAP nonfinancial eligibility standards. See *Noncitizen*.

Poverty guidelines. The poverty guidelines used by FNS are issued by HHS. They are developed on the basis of the poverty thresholds issued by the Census Bureau. Dividing the guidelines by 12 yields the monthly net income limits for SNAP. See also Appendix C.

Preschool-age children. Children under age 5.

Pure public assistance (PA). A household is considered to be pure PA if each member of the household receives SSI, a cash TANF benefit, or GA income.

Refugees. Noncitizens accorded refugee status. In the tables in this report, the term "refugee" includes refugees, asylees, and deportees.

Resource limit. For all non-categorically eligible households without an elderly member or individual with a disability, the resource limit was $2,000 in fiscal year 2014. Households with an elderly individual or individual with a disability were allowed up to $3,250 in countable resources. See also *Countable resources*.

Rural. A household is considered rural if the county in which its local SNAP agency is located is not in a Metropolitan Statistical Area or a Micropolitan Statistical Area.

School-age children. Children age 5 to 17.

Shelter deduction. See *Excess shelter expense deduction*.

Single adult with children households. Households with exactly one person age 18 or older, no spouse, and at least one person under age 18.

Single-person households. Households with exactly one person.

SSI Combined Application Project (SSI-CAP). Joint FNS-SSA-State partnerships with a goal of streamlining the procedures for providing SNAP benefits to certain households eligible for SSI.

Standard deduction. Deduction received by all households, which varies by household size and for areas outside of the 48 contiguous States and the District of Columbia to reflect price differences among geographic areas. See also Appendix C and *Deductions*.

Standard Utility Allowance (SUA). Specified dollar amounts set by State agencies that States may use in place of actual utility costs to calculate a household's total shelter expenses.

Student. Participant age 18 or older enrolled at least half-time in a recognized school, training program, or institution of higher education.

Thrifty Food Plan. Market basket of goods based on an economical and nutritious diet, adjusted for household size and composition. Used to determine maximum SNAP benefit amounts.

Time limits and additional work requirements for adults age 18 to 49 without disabilities in childless households. SNAP participants without disabilities age 18 to 49 who do not live with a household member under the age of 18 are generally subject to time limited participation unless they fulfill additional work requirements beyond the SNAP general work requirements. (See *Work requirements*.) In order to receive SNAP benefits for more than 3 months in a 36-month period, these individuals are required to work or participate in a work program at least 20 hours a week, or participate and comply with a workfare program. States can apply to waive this requirement in certain areas where there are insufficient jobs. States are also issued a limited number of exemptions from the requirement each year, which they can assign to individuals to let them receive benefits for a longer period of time. In this report, all adults meeting this definition, regardless of exemption status, are identified as Adults Age 18 to 49 Without Disabilities in Childless Households

Total deduction. Includes child support payment, dependent care, earned income, excess shelter expense, medical, and standard deductions to which SNAP households are entitled. In some cases, the total deduction exceeds the amount deducted from gross income because net income may not be less than zero. See also *Deductions*.

Unearned income. Includes TANF, GA, SSI, Social Security, unemployment benefits, veterans' benefits, workers' compensation, other government benefits, contributions, deemed income, education loans, child support, wage supplementations, energy assistance, State diversion payments, and other unearned income.

Work requirements. Many SNAP participants without disabilities are required to register for work or be registered by the State agency, must participate in a State employment and training or workfare program if assigned by the State agency, and must agree to accept any suitable job offered to them. Individuals exempt from SNAP work registration rules include the following:

- All individuals under age 16, or age 60 and over, and some individuals age 16 and 17
- Individuals physically or mentally unfit for work
- Individuals complying with work requirements of other assistance programs under TANF
- Individuals responsible for the care of a dependent child under age 6 or the care of an incapacitated person
- Individuals receiving unemployment compensation
- Regular participants in a drug addiction or alcohol treatment program
- Individuals working 30 hours a week or earning more than an amount equal to 30 hours times the minimum wage
- Students enrolled at least half-time in a school, training program, or institution of higher education

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APPENDIX A

DETAILED TABLES OF SNAP HOUSEHOLD CHARACTERISTICS

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Table A.1. Distribution of participating households, individuals, and benefits by household composition, locality, countable income source, and SNAP benefit amount

Household characteristic	SNAP households		Participants in households with household characteristic		Monthly SNAP benefits	
	Number (000)	Percent	Number (000)	Percent	Dollars (000)	Percent
Total	22,445	100.0	45,874	100.0	5,689,647	100.0
Household composition						
Children	9,789	43.6	31,609	68.9	3,817,969	67.1
School-age	7,603	33.9	26,214	57.1	3,092,269	54.3
Preschool-age	4,869	21.7	16,564	36.1	2,045,818	36.0
No children	12,656	56.4	14,265	31.1	1,871,679	32.9
Elderly individuals	4,255	19.0	5,359	11.7	548,607	9.6
No elderly individuals	18,190	81.0	40,515	88.3	5,141,040	90.4
Non-elderly individuals with disabilities	4,579	20.4	8,681	18.9	858,511	15.1
No non-elderly individuals with disabilities	17,865	79.6	37,193	81.1	4,831,136	84.9
Adults age 18 to 49 without disabilities in childless households[a]	4,333	19.3	5,189	11.3	829,307	14.6
No adults age 18 to 49 without disabilities in childless households	18,112	80.7	40,685	88.7	4,860,340	85.4
Noncitizens	1,360	6.1	3,331	7.3	407,922	7.2
No noncitizens	21,084	93.9	42,543	92.7	5,281,726	92.8
Locality						
Metropolitan	18,317	81.6	37,278	81.3	4,696,138	82.5
Micropolitan[b]	2,255	10.0	4,693	10.2	547,865	9.6
Rural	1,519	6.8	3,249	7.1	374,354	6.6
Unknown locality	354	1.6	653	1.4	71,291	1.3
Countable income source						
Gross income	17,526	78.1	38,108	83.1	4,321,309	76.0
No gross income	4,919	21.9	7,765	16.9	1,368,339	24.0
Net income	12,745	56.8	29,333	63.9	2,828,034	49.7
No net income	9,111	40.6	15,911	34.7	2,766,105	48.6
Not applicable[c]	589	2.6	630	1.4	95,508	1.7
Earned income	7,016	31.3	19,477	42.5	2,090,196	36.7
No earned income	15,429	68.7	26,397	57.5	3,599,452	63.3
Unearned income	12,646	56.3	25,215	55.0	2,840,701	49.9
No unearned income	9,799	43.7	20,659	45.0	2,848,946	50.1
TANF income	1,362	6.1	4,106	8.9	554,512	9.7
No TANF income	21,083	93.9	41,768	91.1	5,135,135	90.3
GA income	694	3.1	1,079	2.4	148,890	2.6
No GA income	21,751	96.9	44,795	97.6	5,540,757	97.4
SSI	4,568	20.4	8,026	17.5	858,902	15.1
No SSI	17,877	79.6	37,848	82.5	4,830,746	84.9
Social Security income	5,505	24.5	8,306	18.1	750,919	13.2
No Social Security income	16,940	75.5	37,568	81.9	4,938,729	86.8
Gross countable income as a percentage of poverty guideline						
No income	4,919	21.9	7,765	16.9	1,368,339	24.0
>0-50%	4,755	21.2	12,338	26.9	1,924,069	33.8
51-100%	9,088	40.5	18,163	39.6	1,991,623	35.0
101-130%	2,602	11.6	5,688	12.4	334,813	5.9
131%+	1,081	4.8	1,919	4.2	70,803	1.2
SNAP benefit						
Minimum benefit	1,433	6.4	1,717	3.7	21,628	0.4
Maximum benefit	9,414	41.9	16,214	35.3	2,823,639	49.6

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] With some exceptions, these participants are subject to work requirements and a time limit.

[b] A micropolitan area has at least one urban cluster of between 10,000 and 50,000 people and includes adjacent territory with a high degree of social and economic integration with the core, as measured by commuting ties.

[c] Net income is not used in the benefit determinations of MFIP households or SSI-CAP households in States that use standardized SSI-CAP benefits.

Table A.2. Average gross countable income as a percentage of poverty guideline, gross and net countable income, total deduction, SNAP benefit, household size, and certification period of participating households by household composition, locality, countable income source, and SNAP benefit amount

Household characteristic	Total households: Number (000)	Total households: Percent	Average values: Gross countable income as a percentage of poverty guideline (percent)	Gross countable income (dollars)	Net countable income (dollars)[a]	Total deduction (dollars)[b]	SNAP benefit (dollars)	Household size (individuals)	Certification period (months)
Total	22,445	100.0	57.8	759	335	538	253	2.0	12.9
Household composition									
Children	9,789	43.6	56.0	965	449	615	390	3.2	9.8
School-age	7,603	33.9	57.3	1,025	495	622	407	3.4	9.8
Preschool-age	4,869	21.7	53.6	955	427	629	420	3.4	9.6
No children	12,656	56.4	59.2	600	243	476	148	1.1	15.4
Elderly individuals	4,255	19.0	83.7	876	407	544	129	1.3	19.5
No elderly individuals	18,190	81.0	51.7	732	319	536	283	2.2	11.4
Non-elderly individuals with disabilities	4,579	20.4	82.4	1,006	501	543	187	1.9	16.7
No non-elderly individuals with disabilities	17,865	79.6	51.5	696	294	536	270	2.1	12.0
Adults age 18 to 49 without disabilities in childless households[c]	4,333	19.3	28.7	314	113	410	191	1.2	9.8
No adults age 18 to 49 without disabilities in childless households	18,112	80.7	64.8	866	390	569	268	2.2	13.7
Noncitizens	1,360	6.1	59.6	887	371	637	300	2.4	13.0
No noncitizens	21,084	93.9	57.7	751	333	531	251	2.0	12.9
Locality									
Metropolitan	18,317	81.6	57.3	753	319	553	256	2.0	12.8
Micropolitan[d]	2,255	10.0	59.8	788	398	479	243	2.1	12.8
Rural	1,519	6.8	57.7	778	417	452	246	2.1	13.2
Unknown locality	354	1.6	67.9	833	393	504	202	1.8	20.6
Countable income source									
Gross income	17,526	78.1	74.0	972	432	601	247	2.2	13.7
No gross income	4,919	21.9	0.0	0	0	320	278	1.6	10.3
Net income	12,745	56.8	85.0	1,148	575	573	222	2.3	13.2
No net income	9,111	40.6	18.3	215	0	489	304	1.7	10.9
Not applicable	589	2.6	80.0	771	–	75	162	1.1	38.1
Earned income	7,016	31.3	78.9	1,221	544	728	298	2.8	9.8
No earned income	15,429	68.7	48.2	549	237	448	233	1.7	14.4
Unearned income	12,646	56.3	74.0	914	424	547	225	2.0	15.3
No unearned income	9,799	43.7	36.9	559	226	526	291	2.1	9.9
TANF income	1,362	6.1	44.7	737	292	516	407	3.0	10.9
No TANF income	21,083	93.9	58.6	761	338	539	244	2.0	13.1
GA income	694	3.1	49.6	594	212	537	215	1.6	13.7
No GA income	21,751	96.9	58.1	765	339	538	255	2.1	12.9
SSI	4,568	20.4	75.9	905	428	518	188	1.8	19.8
No SSI	17,877	79.6	53.2	722	314	542	270	2.1	11.2
Social Security income	5,505	24.5	92.5	1,019	504	550	136	1.5	17.3
No Social Security income	16,940	75.5	46.5	675	281	534	292	2.2	11.5
SNAP benefit									
Minimum benefit	1,433	6.4	128.4	1,327	962	365	15	1.2	15.4
Maximum benefit	9,414	41.9	20.4	234	0	489	300	1.7	11.8

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Because net income is not used in their benefit determinations, 23,481 MFIP households and 565,481 SSI-CAP households in States that use standardized SSI-CAP benefits are excluded from this column. Thus, the average values are based on fewer households than the number shown in the Total Households column.

[b] Because deductions are not used in their benefit determinations, 565,481 SSI-CAP households in States that use standardized SSI-CAP benefits are excluded from this column. Thus, the average values are based on fewer households than the number shown in the Total Households column.

[c] With some exceptions, these participants are subject to work requirements and a time limit.

[d] A micropolitan area has at least one urban cluster of between 10,000 and 50,000 people and includes adjacent territory with a high degree of social and economic integration with the core, as measured by commuting ties.

– Not applicable.

Table A.3. Distribution of participating households with children, elderly individuals, and non-elderly individuals with disabilities by amount of gross and net countable income, countable resources, and gross and net countable income as a percentage of poverty guideline

Household characteristic	Total households		Households with:					
			Children		Elderly individuals		Non-elderly individuals with disabilities	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total	22,445	100.0	9,789	100.0	4,255	100.0	4,579	100.0
Gross countable income								
$0	4,919	21.9	1,376	14.1	308	7.2	0	0.0
1-199	906	4.0	399	4.1	44	1.0	3	0.1
200-399	1,378	6.1	810	8.3	100	2.3	23	0.5
400-599	1,558	6.9	982	10.0	209	4.9	142	3.1
600-799	4,429	19.7	1,082	11.1	1,405	33.0	2,020	44.1
800-999	2,676	11.9	880	9.0	859	20.2	864	18.9
1,000-1,249	2,272	10.1	1,024	10.5	667	15.7	587	12.8
1,250-1,499	1,517	6.8	930	9.5	344	8.1	378	8.2
1,500-1,999	1,630	7.3	1,264	12.9	226	5.3	342	7.5
2,000+	1,159	5.2	1,040	10.6	94	2.2	220	4.8
Net countable income								
$0	9,111	40.6	3,500	35.8	917	21.6	546	11.9
1-199	2,877	12.8	1,256	12.8	585	13.7	748	16.3
200-399	2,828	12.6	1,016	10.4	791	18.6	940	20.5
400-599	2,368	10.6	913	9.3	682	16.0	800	17.5
600-799	1,382	6.2	733	7.5	341	8.0	378	8.2
800-999	1,168	5.2	685	7.0	306	7.2	304	6.6
1,000+	2,121	9.4	1,661	17.0	328	7.7	602	13.2
Not applicable[a]	589	2.6	25	0.3	305	7.2	261	5.7
Countable resources								
Categorically eligible[b]	20,538	91.5	8,868	90.6	3,994	93.9	4,277	93.4
$0	1,124	5.0	518	5.3	74	1.7	143	3.1
1-500	584	2.6	296	3.0	130	3.1	118	2.6
501-1,000	108	0.5	58	0.6	30	0.7	24	0.5
1,001-2,000	76	0.3	47	0.5	18	0.4	13	0.3
2,001-3,250	13	0.1	2	0.0	8	0.2	5	0.1
Gross countable income as a percentage of poverty guideline								
No gross income	4,919	21.9	1,376	14.1	308	7.2	0	0.0
>0-25%	1,959	8.7	1,233	12.6	81	1.9	25	0.5
26-50%	2,796	12.5	2,074	21.2	204	4.8	422	9.2
51-75%	3,979	17.7	1,997	20.4	754	17.7	1,451	31.7
76-100%	5,109	22.8	1,564	16.0	1,775	41.7	1,828	39.9
101-125%	2,350	10.5	1,072	10.9	656	15.4	555	12.1
126-130%	253	1.1	123	1.3	69	1.6	60	1.3
131-150%	588	2.6	211	2.2	222	5.2	125	2.7
151%+	494	2.2	139	1.4	188	4.4	113	2.5
Net countable income as a percentage of poverty guideline								
No net income	9,111	40.6	3,500	35.8	917	21.6	546	11.9
>0-25%	4,502	20.1	2,411	24.6	772	18.1	1,166	25.5
26-50%	3,979	17.7	1,868	19.1	1,014	23.8	1,254	27.4
51-75%	2,627	11.7	1,274	13.0	681	16.0	847	18.5
76-100%	1,206	5.4	622	6.4	358	8.4	376	8.2
101-125%	264	1.2	65	0.7	123	2.9	78	1.7
126-130%	29	0.1	5	0.1	14	0.3	8	0.2
131-150%	75	0.3	11	0.1	41	1.0	28	0.6
151%+	63	0.3	7	0.1	29	0.7	16	0.3
Not applicable[a]	589	2.6	25	0.3	305	7.2	261	5.7

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Net income is not used in the benefit determinations of MFIP households or SSI-CAP households in States that use standardized SSI-CAP benefits.

[b] Categorically eligible households have no countable resources because the program does not consider resources in their eligibility determinations. However, in fiscal year 2014, five States (Idaho, Michigan, Nebraska, Pennsylvania, and Texas) used resource limits between $5,000 and $25,000 when determining eligibility.

Table A.4. Distribution of participating households by household size and amount of countable gross and net income, resources, and gross and net income as a percentage of poverty guideline

Household characteristic	Total households		Household size												
			1		2		3		4		5		6+	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total	22,445	100.0	11,670	100.0	4,221	100.0	3,020	100.0	1,927	100.0	1,006	100.0	602	100.0
Gross countable income														
$0	4,919	21.9	3,447	29.5	693	16.4	404	13.4	223	11.6	103	10.3	49	8.2
1-199	906	4.0	517	4.4	186	4.4	122	4.0	54	2.8	18	1.8	9	1.6
200-399	1,378	6.1	631	5.4	371	8.8	195	6.5	114	5.9	44	4.3	23	3.9
400-599	1,558	6.9	639	5.5	430	10.2	289	9.6	133	6.9	44	4.4	23	3.8
600-799	4,429	19.7	3,207	27.5	552	13.1	375	12.4	176	9.1	81	8.1	38	6.4
800-999	2,676	11.9	1,673	14.3	453	10.7	278	9.2	165	8.5	59	5.9	48	7.9
1,000-1,249	2,272	10.1	963	8.2	585	13.9	349	11.6	228	11.8	94	9.3	53	8.8
1,250-1,499	1,517	6.8	376	3.2	456	10.8	353	11.7	186	9.6	97	9.6	49	8.2
1,500-1,999	1,630	7.3	182	1.6	341	8.1	464	15.4	339	17.6	191	19.0	112	18.6
2,000+	1,159	5.2	36	0.3	153	3.6	189	6.2	311	16.1	274	27.2	197	32.7
Net countable income														
$0	9,111	40.6	5,570	47.7	1,698	40.2	974	32.3	511	26.5	238	23.7	121	20.1
1-199	2,877	12.8	1,530	13.1	594	14.1	435	14.4	216	11.2	62	6.2	39	6.6
200-399	2,828	12.6	1,676	14.4	485	11.5	317	10.5	215	11.2	80	8.0	54	8.9
400-599	2,368	10.6	1,293	11.1	437	10.3	335	11.1	168	8.7	87	8.6	49	8.2
600-799	1,382	6.2	508	4.4	331	7.8	259	8.6	162	8.4	75	7.4	48	7.9
800-999	1,168	5.2	326	2.8	285	6.7	247	8.2	170	8.8	96	9.5	45	7.5
1,000-1,199	741	3.3	98	0.8	159	3.8	209	6.9	143	7.4	86	8.5	46	7.6
1,200+	1,380	6.1	103	0.9	221	5.2	238	7.9	338	17.5	281	27.9	199	33.1
Not applicable[a]	589	2.6	567	4.9	10	0.2	6	0.2	4	0.2	1	0.1	1	0.1
Countable resources														
Categorically eligible[b]	20,538	91.5	10,791	92.5	3,872	91.7	2,717	90.0	1,722	89.4	894	88.9	542	90.1
$0	1,124	5.0	567	4.9	198	4.7	174	5.8	103	5.3	53	5.3	29	4.8
1-500	584	2.6	237	2.0	115	2.7	99	3.3	74	3.8	38	3.8	21	3.4
501-1,000	108	0.5	38	0.3	22	0.5	16	0.5	16	0.8	11	1.0	5	0.8
1,001-2,000	76	0.3	27	0.2	12	0.3	12	0.4	12	0.6	9	0.9	5	0.8
2,001-3,250	13	0.1	10	0.1	2	0.0	1	0.0	0	0.0	0	0.0	0	0.0
Gross countable income as a percentage of poverty guideline														
No gross income	4,919	21.9	3,447	29.5	693	16.4	404	13.4	223	11.6	103	10.3	49	8.2
>0-25%	1,959	8.7	718	6.1	465	11.0	347	11.5	246	12.7	104	10.3	80	13.3
26-50%	2,796	12.5	748	6.4	642	15.2	663	22.0	389	20.2	206	20.5	148	24.6
51-75%	3,979	17.7	1,784	15.3	842	19.9	569	18.9	405	21.0	229	22.8	150	25.0
76-100%	5,109	22.8	3,215	27.5	736	17.4	528	17.5	340	17.6	186	18.5	104	17.3
101-125%	2,350	10.5	1,063	9.1	490	11.6	361	12.0	244	12.7	136	13.5	56	9.2
126-130%	253	1.1	108	0.9	56	1.3	43	1.4	29	1.5	13	1.3	3	0.5
131-150%	588	2.6	315	2.7	125	3.0	76	2.5	38	1.9	24	2.3	11	1.8
151%+	494	2.2	273	2.3	173	4.1	28	0.9	15	0.8	5	0.5	0	0.0
Net countable income as a percentage of poverty guideline														
No net income	9,111	40.6	5,570	47.7	1,698	40.2	974	32.3	511	26.5	238	23.7	121	20.1
>0-25%	4,502	20.1	1,901	16.3	901	21.3	785	26.0	523	27.2	229	22.8	164	27.2
26-50%	3,979	17.7	1,862	16.0	719	17.0	599	19.8	404	21.0	236	23.5	160	26.6
51-75%	2,627	11.7	1,092	9.4	489	11.6	439	14.5	306	15.9	199	19.8	102	17.0
76-100%	1,206	5.4	444	3.8	242	5.7	213	7.1	161	8.3	94	9.4	52	8.6
101-125%	264	1.2	132	1.1	97	2.3	4	0.1	19	1.0	9	0.9	3	0.5
126-130%	29	0.1	16	0.1	14	0.3	–	–	–	–	–	–	–	–
131-150%	75	0.3	45	0.4	30	0.7	–	–	–	–	–	–	0	0.0
151%+	63	0.3	42	0.4	21	0.5	–	–	–	–	–	–	–	–
Not applicable[a]	589	2.6	567	4.9	10	0.2	6	0.2	4	0.2	1	0.1	1	0.1

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Net income is not used in the benefit determinations of MFIP households or SSI-CAP households in States that use standardized SSI-CAP benefits.

[b] Categorically eligible households have no countable resources because the program does not consider resources in their eligibility determinations. However, in fiscal year 2014, five States (Idaho, Michigan, Nebraska, Pennsylvania, and Texas) used resource limits between $5,000 and $25,000 when determining eligibility.

– No sample households in this category.

Table A.5. Average gross and net countable income, average gross and net countable income as a percentage of poverty guideline, average countable resources, and average benefit of participating households by household composition and size

Household characteristic	Total households		Average values					
	Number (000)	Percent	Gross countable income (dollars)	Net countable income (dollars)[a]	Gross countable income as a percentage of poverty guideline (percent)	Net countable income as a percentage of poverty guideline (percent)[a]	Countable resources among households with countable resources (dollars)	SNAP benefit (dollars)
Total	22,445	100.0	759	335	57.8	24.1	446	253
Household composition								
Children	9,789	43.6	965	449	56.0	24.9	412	390
School-age	7,603	33.9	1,025	495	57.3	26.6	428	407
Preschool-age	4,869	21.7	955	427	53.6	22.5	416	420
No children	12,656	56.4	600	243	59.2	23.5	480	148
Elderly individuals	4,255	19.0	876	407	83.7	37.7	570	129
No elderly individuals	18,190	81.0	732	319	51.7	21.1	407	283
Non-elderly individuals with disabilities	4,579	20.4	1,006	501	82.4	37.9	464	187
No non-elderly individuals with disabilities	17,865	79.6	696	294	51.5	20.7	441	270
Household size								
1	11,670	52.0	542	199	56.4	20.7	453	140
2	4,221	18.8	793	337	61.3	26.0	446	255
3	3,020	13.5	934	418	57.4	25.6	400	376
4	1,927	8.6	1,142	580	58.1	29.5	408	463
5	1,006	4.5	1,396	771	60.7	33.5	467	527
6	381	1.7	1,479	823	56.1	31.2	679	664
7	140	0.6	1,702	993	57.3	33.4	476	711
8+	81	0.4	1,816	1,174	51.2	33.0	566	905

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Because net income is not used in their benefit determinations, 23,481 MFIP households and 565,481 SSI-CAP households in States that use standardized SSI-CAP benefits are excluded from this column. Thus, the average values are based on fewer households than the number shown in the Total Households column.

Table A.6. Distribution of participating households with children, elderly individuals, and non-elderly individuals with disabilities by type of countable income

Type of income	Total households		Households with:					
			Children		Elderly individuals		Non-elderly individuals with disabilities	
	Number (000)[a]	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total	22,445	100.0	9,789	100.0	4,255	100.0	4,579	100.0
Countable earned income	7,016	31.3	5,113	52.2	291	6.8	518	11.3
Wages and salaries	6,178	27.5	4,578	46.8	232	5.5	469	10.2
Self-employment	914	4.1	614	6.3	61	1.4	51	1.1
Other earned income	71	0.3	42	0.4	2	0.1	4	0.1
Countable unearned income	12,646	56.3	4,970	50.8	3,817	89.7	4,577	99.9
Temporary Assistance for Needy Families	1,362	6.1	1,313	13.4	37	0.9	245	5.4
General Assistance	694	3.1	142	1.5	159	3.7	152	3.3
Supplemental Security Income	4,568	20.4	1,125	11.5	1,556	36.6	3,101	67.7
Social Security	5,505	24.5	871	8.9	2,914	68.5	2,354	51.4
Unemployment income	466	2.1	263	2.7	21	0.5	21	0.4
Veterans' benefits	163	0.7	38	0.4	67	1.6	40	0.9
Workers' compensation	47	0.2	24	0.2	7	0.2	14	0.3
Other government benefits[b]	149	0.7	62	0.6	60	1.4	46	1.0
Household contributions	642	2.9	407	4.2	71	1.7	35	0.8
Household deemed income	18	0.1	17	0.2	0	0.0	1	0.0
Educational loans	8	0.0	6	0.1	0	0.0	2	0.0
Child support enforcement payments	1,870	8.3	1,781	18.2	29	0.7	292	6.4
Foster care payments	9	0.0	6	0.1	2	0.0	5	0.1
State diversion payments	1	0.0	1	0.0	0	0.0	0	0.0
Energy assistance income	3	0.0	1	0.0	1	0.0	0	0.0
Wage supplementation	0	0.0	0	0.0	0	0.0	0	0.0
Other unearned income[c]	720	3.2	251	2.6	346	8.1	85	1.9
TANF or GA	2,047	9.1	1,446	14.8	195	4.6	391	8.5
TANF and earnings	308	1.4	302	3.1	4	0.1	20	0.4
TANF and SSI	234	1.0	227	2.3	17	0.4	224	4.9
TANF or SSI or GA	6,184	27.6	2,301	23.5	1,658	39.0	3,140	68.6
(TANF or SSI or GA) and earnings	744	3.3	583	6.0	32	0.8	386	8.4
TANF and child support	109	0.5	107	1.1	2	0.0	28	0.6
SSI and Social Security	1,706	7.6	263	2.7	857	20.1	910	19.9
SSI or Social Security	8,367	37.3	1,733	17.7	3,613	84.9	4,545	99.3
SSI and earnings	405	1.8	263	2.7	29	0.7	382	8.4
GA and earnings	61	0.3	41	0.4	2	0.0	12	0.3
Earnings and child support	832	3.7	810	8.3	8	0.2	62	1.3
No countable income	4,919	21.9	1,376	14.1	308	7.2	0	0.0

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] The sum of individual income sources does not add to the total because households may receive income from more than one source.

[b] Examples of other government benefits include Black Lung Benefits, Railroad Retirement payments, and USDA payments to farmers.

[c] Examples of other unearned income include alimony and dividends and interest payments.

Table A.7. Average income, total deduction, SNAP benefit, and household size of participating households by type of countable income

Type of Income	Total households		Average values					
	Number (000)[a]	Percent	Gross countable income (dollars)	Net countable income (dollars)[b]	Income source (dollars)[c]	Total deduction (dollars)[d]	SNAP benefit (dollars)	Household size (individuals)
Total	22,445	100.0	759	335	-	538	253	2.0
Countable earned income	7,016	31.3	1,221	544	1,064	728	298	2.8
Wages and salaries	6,178	27.5	1,293	589	1,128	742	292	2.8
Self-employment	914	4.1	805	280	520	653	349	2.6
Other earned income	71	0.3	755	298	261	602	280	2.0
Countable unearned income	12,646	56.3	914	424	758	547	225	2.0
Temporary Assistance for Needy Families	1,362	6.1	737	292	383	516	407	3.0
General Assistance	694	3.1	594	212	225	537	215	1.6
Supplemental Security Income	4,568	20.4	905	428	589	518	188	1.8
Social Security	5,505	24.5	1,019	504	820	550	136	1.5
Unemployment income	466	2.1	1,041	543	790	536	252	2.4
Veterans' benefits	163	0.7	1,134	656	556	511	145	1.8
Workers' compensation	47	0.2	1,372	771	976	621	263	2.9
Other government benefits[e]	149	0.7	1,100	565	465	588	232	2.3
Household contributions	642	2.9	650	228	285	528	344	2.5
Household deemed income	18	0.1	783	331	556	584	242	1.9
Educational loans	8	0.0	1,179	580	511	675	297	2.9
Child support enforcement payments	1,870	8.3	1,084	559	350	581	373	3.3
Foster care payments	9	0.0	1,396	1037	663	433	246	3.5
State diversion payments	1	0.0	1,619	1075	105	547	78	2.2
Energy assistance income	3	0.0	975	391	567	641	157	1.6
Wage supplementation	0	0.0	1,790	863	500	927	491	5.0
Other unearned income[f]	720	3.2	1,086	540	367	612	192	1.9
TANF or GA	2,047	9.1	687	263	331	523	342	2.5
TANF and earnings	308	1.4	1,118	496	1,047	653	381	3.2
TANF and SSI	234	1.0	1,235	751	1,054	493	332	3.5
TANF or SSI or GA	6,184	27.6	819	355	545	520	234	1.9
(TANF or SSI or GA) and earnings	744	3.3	1,397	741	1,297	680	302	3.2
TANF and child support	109	0.5	954	470	554	523	427	3.5
SSI and Social Security	1,706	7.6	900	437	848	493	153	1.5
SSI or Social Security	8,367	37.3	981	478	861	544	161	1.6
SSI and earnings	405	1.8	1,639	971	1,475	689	244	3.2
GA and earnings	61	0.3	1,331	611	1,121	738	299	3.0
Earnings and child support	832	3.7	1,575	849	1,486	740	318	3.6
No countable income	4,919	21.9	0	0	0	320	278	1.6

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] The sum of individual income sources does not add to the total because households may receive income from more than one source.

[b] Because net income is not used in their benefit determinations, 23,481 MFIP households and 565,481 SSI-CAP households in States that use standardized SSI-CAP benefits are excluded from this column. Thus, the average values are based on fewer households than the number shown in the Total Households column.

[c] Average value of specified source over households with income from source.

[d] Because deductions are not used in their benefit determinations, 565,481 SSI-CAP households in States that use standardized SSI-CAP benefits are excluded from this column. Thus, the average values are based on fewer households than the number shown in the Total Households column.

[e] Examples of other government benefits include Black Lung Benefits, Railroad Retirement payments, and USDA payments to farmers.

[f] Examples of other unearned income include alimony and dividends and interest payments.

Table A.8. Distribution of participating households with children, elderly individuals, and non-elderly individuals with disabilities by countable earned and unearned income amounts

Household characteristic	Total households		Households with:					
			Children		Elderly individuals		Non-elderly individuals with disabilities	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total	22,445	100.0	9,789	100.0	4,255	100.0	4,579	100.0
Countable earned income								
$0	15,429	68.7	4,676	47.8	3,964	93.2	4,062	88.7
1-199	609	2.7	241	2.5	51	1.2	118	2.6
200-399	625	2.8	348	3.6	45	1.1	57	1.2
400-599	684	3.0	453	4.6	34	0.8	57	1.2
600-799	835	3.7	549	5.6	50	1.2	66	1.4
800-999	850	3.8	598	6.1	33	0.8	51	1.1
1,000-1,249	966	4.3	724	7.4	27	0.6	59	1.3
1,250-1,499	747	3.3	630	6.4	15	0.4	38	0.8
1,500-1,999	986	4.4	881	9.0	24	0.6	46	1.0
2,000+	714	3.2	688	7.0	11	0.3	26	0.6
Countable unearned income								
$0	9,799	43.7	4,819	49.2	438	10.3	3	0.1
1-199	986	4.4	634	6.5	45	1.0	9	0.2
200-399	1,482	6.6	1,086	11.1	96	2.3	38	0.8
400-599	1,385	6.2	949	9.7	204	4.8	182	4.0
600-799	4,084	18.2	869	8.9	1,409	33.1	2,235	48.8
800-999	1,953	8.7	403	4.1	842	19.8	868	19.0
1,000-1,249	1,403	6.3	379	3.9	663	15.6	593	13.0
1,250-1,499	724	3.2	290	3.0	315	7.4	340	7.4
1,500+	629	2.8	359	3.7	243	5.7	311	6.8
Countable TANF income								
$0	21,083	93.9	8,476	86.6	4,219	99.1	4,334	94.6
1-199	253	1.1	234	2.4	14	0.3	84	1.8
200-399	509	2.3	489	5.0	14	0.3	94	2.1
400-599	421	1.9	413	4.2	6	0.1	47	1.0
600-799	136	0.6	134	1.4	1	0.0	14	0.3
800-999	35	0.2	35	0.4	2	0.0	3	0.1
1,000+	9	0.0	9	0.1	0	0.0	4	0.1
Countable GA income								
$0	21,751	96.9	9,646	98.5	4,096	96.3	4,427	96.7
1-199	352	1.6	51	0.5	96	2.3	122	2.7
200-399	234	1.0	33	0.3	40	0.9	15	0.3
400-599	80	0.4	39	0.4	16	0.4	13	0.3
600-799	14	0.1	7	0.1	5	0.1	1	0.0
800-999	6	0.0	5	0.1	0	0.0	0	0.0
1,000+	8	0.0	6	0.1	2	0.1	1	0.0
Countable TANF or GA income								
$0	20,398	90.9	8,342	85.2	4,060	95.4	4,189	91.5
1-199	597	2.7	278	2.8	109	2.6	199	4.4
200-399	740	3.3	519	5.3	54	1.3	107	2.3
400-599	502	2.2	453	4.6	22	0.5	61	1.3
600-799	150	0.7	141	1.4	6	0.1	16	0.3
800-999	41	0.2	41	0.4	2	0.0	3	0.1
1,000+	18	0.1	15	0.2	3	0.1	4	0.1

See footnotes at end of table.

Table A.8. Distribution of participating households with children, elderly individuals, and non-elderly individuals with disabilities by countable earned and unearned income amounts — Continued

Household characteristic	Total households		Households with:					
			Children		Elderly individuals		Non-elderly individuals with disabilities	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Countable SSI								
$0	17,877	79.6	8,663	88.5	2,700	63.4	1,478	32.3
1-199	750	3.3	69	0.7	398	9.3	357	7.8
200-399	569	2.5	76	0.8	277	6.5	297	6.5
400-599	475	2.1	96	1.0	187	4.4	294	6.4
600-799	2,176	9.7	609	6.2	499	11.7	1,703	37.2
800-999	278	1.2	69	0.7	114	2.7	175	3.8
1,000+	320	1.4	208	2.1	81	1.9	275	6.0
Maximum for one-person[a]	1,230	5.5	252	2.6	292	6.9	946	20.7
Maximum for two-persons[b]	35	0.2	3	0.0	28	0.7	13	0.3
Countable Social Security								
$0	16,940	75.5	8,918	91.1	1,341	31.5	2,226	48.6
1-199	184	0.8	108	1.1	43	1.0	115	2.5
200-399	486	2.2	131	1.3	223	5.2	219	4.8
400-599	782	3.5	133	1.4	423	9.9	312	6.8
600-799	1,346	6.0	150	1.5	725	17.0	568	12.4
800-999	1,249	5.6	104	1.1	645	15.2	560	12.2
1,000+	1,459	6.5	244	2.5	856	20.1	581	12.7
Other countable unearned income								
$0	18,547	82.6	7,109	72.6	3,667	86.2	4,063	88.7
1-199	1,202	5.4	723	7.4	244	5.7	206	4.5
200-399	1,071	4.8	803	8.2	134	3.2	134	2.9
400-599	674	3.0	507	5.2	80	1.9	67	1.5
600-799	339	1.5	228	2.3	55	1.3	38	0.8
800-999	203	0.9	133	1.4	25	0.6	20	0.4
1,000+	400	1.8	284	2.9	50	1.2	48	1.1

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] The fiscal year 2014 maximum monthly SSI benefit for one person was $710 from October through December 2013 and $721 from January through September 2014. This row tabulates the number of households in which at least one person received the applicable maximum SSI benefit.

[b] The fiscal year 2014 maximum monthly SSI benefit for two persons was $1,066 from October through December 2013 and $1,082 from January through September 2014. This row tabulates the number of households in which the two persons receive a combined SSI benefit of this amount.

Table A.9. Distribution of participating households by type of deduction and household composition, countable income source, and SNAP benefit amount

Household characteristic	Total households		Type of deduction										
			Earned income		Dependent care		Excess shelter			Medical		Child support	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Percent with maxi-mum[a]	Number (000)	Percent	Number (000)	Percent
Total	22,445	100.0	6,993	31.2	784	3.5	16,159	72.0	27.7	1,121	5.0	416	1.9
Household composition													
Children	9,789	100.0	5,110	52.2	783	8.0	7,669	78.4	40.6	114	1.2	200	2.0
School-age	7,603	100.0	3,992	52.5	529	7.0	6,037	79.4	40.0	102	1.3	164	2.2
Preschool-age	4,869	100.0	2,687	55.2	537	11.0	3,738	76.8	42.7	32	0.7	94	1.9
No children	12,656	100.0	1,883	14.9	0	0.0	8,490	67.1	16.0	1,007	8.0	216	1.7
Elderly individuals	4,255	100.0	290	6.8	1	0.0	3,231	75.9	0.1	714	16.8	38	0.9
No elderly individuals	18,190	100.0	6,704	36.9	783	4.3	12,928	71.1	34.6	408	2.2	378	2.1
Non-elderly individuals with disabilities	4,579	100.0	504	11.0	58	1.3	3,659	79.9	0.1	431	9.4	129	2.8
No non-elderly individuals with disabilities	17,865	100.0	6,489	36.3	726	4.1	12,500	70.0	35.8	690	3.9	287	1.6
Countable income source													
Gross income	17,526	100.0	6,993	39.9	772	4.4	14,210	81.1	24.5	1,120	6.4	396	2.3
No gross income	4,919	100.0	–	–	12	0.2	1,949	39.6	50.8	1	0.0	20	0.4
Net income	12,745	100.0	5,398	42.4	639	5.0	10,350	81.2	18.5	958	7.5	290	2.3
No net income	9,111	100.0	1,590	17.4	144	1.6	5,809	63.8	44.1	163	1.8	126	1.4
Not applicable[b]	589	100.0	6	1.0	–	–	–	–	–	–	–	–	–
Earned income	7,016	100.0	6,993	99.7	728	10.4	5,839	83.2	41.3	97	1.4	226	3.2
No earned income	15,429	100.0	–	–	56	0.4	10,320	66.9	20.0	1,024	6.6	190	1.2
Unearned income	12,646	100.0	2,119	16.8	308	2.4	10,118	80.0	15.9	1,113	8.8	239	1.9
No unearned income	9,799	100.0	4,874	49.7	475	4.9	6,041	61.7	47.4	8	0.1	178	1.8
TANF income	1,362	100.0	307	22.6	27	2.0	1,119	82.1	37.7	8	0.6	4	0.3
No TANF income	21,083	100.0	6,686	31.7	757	3.6	15,041	71.3	26.9	1,113	5.3	413	2.0
GA income	694	100.0	61	8.7	3	0.4	587	84.5	27.4	7	1.0	6	0.9
No GA income	21,751	100.0	6,933	31.9	781	3.6	15,573	71.6	27.7	1,114	5.1	410	1.9
SSI	4,568	100.0	392	8.6	49	1.1	3,431	75.1	0.1	115	2.5	64	1.4
No SSI	17,877	100.0	6,602	36.9	734	4.1	12,728	71.2	35.1	1,006	5.6	352	2.0
Social Security income	5,505	100.0	398	7.2	25	0.4	4,489	81.5	2.4	1,044	19.0	141	2.6
No Social Security income	16,940	100.0	6,595	38.9	759	4.5	11,670	68.9	37.4	77	0.5	275	1.6
SNAP benefit													
Minimum benefit	1,433	100.0	333	23.2	9	0.6	835	58.3	2.1	306	21.4	23	1.6
Maximum benefit	9,414	100.0	1,590	16.9	144	1.5	5,809	61.7	44.1	163	1.7	126	1.3

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Percentage of households with deduction that receive the maximum.

[b] Net income is not used in the benefit determinations of MFIP households or SSI-CAP households in States that use standardized SSI-CAP benefits.

– No sample households in this category.

Table A.10. Average values of deductions of participating households by household composition, countable income source, and SNAP benefit amount

Household characteristic	Total house-holds (000)	Average amount of deduction (dollars): Earned income[a]		Dependent care[b]		Excess shelter[c]		Medical[b]		Child support[c]	
		All households	With deduction	All households	With deduction	All households	With deduction	All households	With deduction	All households	With deduction
Total	22,445	69	213	10	276	290	393	8	155	4	229
Household composition											
Children	9,789	125	240	22	276	298	380	2	137	5	250
School-age	7,603	130	247	19	268	302	379	2	138	6	258
Preschool-age	4,869	135	244	32	287	293	381	1	132	5	240
No children	12,656	22	140	0	17	284	404	13	157	4	210
Elderly individuals	4,255	11	151	0	184	350	428	29	160	2	163
No elderly individuals	18,190	81	216	12	276	277	384	3	146	5	236
Non-elderly individuals with disabilities	4,579	19	161	5	356	342	404	15	145	6	196
No non-elderly individuals with disabilities	17,865	81	217	11	270	277	389	6	161	4	244
Countable income source											
Gross income	17,526	89	213	13	277	327	390	10	155	5	226
No gross income	4,919	0	0	0	176	163	411	0	138	1	288
Net income	12,745	108	251	14	269	279	343	10	137	5	228
No net income	9,111	15	84	5	308	306	480	5	257	3	233
Not applicable[d]	589	75	295	0	0	0	0	0	0	0	0
Earned income	7,016	213	213	29	277	315	378	3	190	8	253
No earned income	15,429	0	0	1	266	279	401	11	151	3	201
Unearned income	12,646	33	187	8	308	332	395	14	155	4	209
No unearned income	9,799	112	225	12	255	239	388	0	170	5	256
TANF income	1,362	33	146	6	300	320	384	1	154	0	167
No TANF income	21,083	71	216	10	275	288	393	8	155	5	230
GA income	694	16	175	1	316	360	422	1	89	1	105
No GA income	21,751	70	214	10	276	288	391	8	155	5	231
SSI	4,568	18	174	5	356	334	389	3	115	3	174
No SSI	17,877	80	216	11	270	280	393	9	159	5	239
Social Security income	5,505	10	134	1	298	348	408	31	155	5	186
No Social Security income	16,940	87	218	13	275	272	387	1	148	4	251
SNAP benefit											
Minimum benefit	1,433	59	255	1	212	123	211	26	120	3	196
Maximum benefit	9,414	15	84	5	308	306	480	5	257	3	233

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Because this deduction is not used in their benefit determinations, 720,552 SSI-CAP households are excluded from this column. Thus, the average values are based on fewer households than the number shown in the Total Households column.

[b] Because this deduction is not used in their benefit determinations, 23,481 MFIP households and 720,552 SSI-CAP households are excluded from this column. Thus, the average values are based on fewer households than the number shown in the Total Households column.

[c] Because this deduction is not used in their benefit determinations, 23,481 MFIP households and 565,481 SSI-CAP households in States that use standardized SSI-CAP benefits are excluded from this column. Thus, the average values are based on fewer households than the number shown in the Total Households column.

[d] Net income is not used in the benefit determinations of MFIP households or SSI-CAP households in States that use standardized SSI-CAP benefits.

Table A.11. Distribution of participating households by selected household characteristics and amount of deduction

Household characteristic	Total households		Households with:							
			Children		Elderly individuals		Non-elderly individuals with disabilities		Countable earned income	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total	22,445	100.0	9,789	100.0	4,255	100.0	4,579	100.0	7,016	100.0
Total deduction										
$0-151[a]	24	0.1	21	0.2	1	0.0	0	0.0	4	0.1
152	3,866	17.2	892	9.1	552	13.0	367	8.0	3	0.0
153-200	913	4.1	474	4.8	127	3.0	198	4.3	182	2.6
201-300	1,337	6.0	454	4.6	394	9.3	457	10.0	271	3.9
301-400	1,538	6.9	585	6.0	442	10.4	532	11.6	391	5.6
401-500	2,045	9.1	802	8.2	490	11.5	602	13.2	578	8.2
501-600	2,366	10.5	988	10.1	484	11.4	518	11.3	728	10.4
601-700	4,091	18.2	2,179	22.3	390	9.2	522	11.4	1,018	14.5
701-800	1,930	8.6	1,056	10.8	344	8.1	385	8.4	1,282	18.3
801-900	1,505	6.7	898	9.2	219	5.1	263	5.8	1,073	15.3
901-1,000	877	3.9	569	5.8	145	3.4	176	3.8	605	8.6
1,001+	1,387	6.2	867	8.9	362	8.5	298	6.5	875	12.5
Not applicable[b]	565	2.5	2	0.0	304	7.2	261	5.7	6	0.1
Earned income deduction										
$0	14,731	65.6	4,677	47.8	3,595	84.5	3,725	81.3	16	0.2
1-50	800	3.6	358	3.7	67	1.6	132	2.9	800	11.4
51-100	751	3.3	450	4.6	43	1.0	61	1.3	751	10.7
101-150	974	4.3	645	6.6	55	1.3	79	1.7	974	13.9
151-200	1,092	4.9	760	7.8	50	1.2	65	1.4	1,092	15.6
201-250	943	4.2	710	7.3	24	0.6	59	1.3	943	13.4
251-300	756	3.4	633	6.5	15	0.4	38	0.8	756	10.8
301-350	583	2.6	511	5.2	13	0.3	34	0.7	583	8.3
351-400	392	1.7	368	3.8	11	0.3	11	0.2	392	5.6
401+	702	3.1	676	6.9	11	0.3	26	0.6	702	10.0
Not applicable[c]	721	3.2	2	0.0	370	8.7	350	7.6	6	0.1
Dependent care deduction										
$0	20,917	93.2	8,981	91.7	3,884	91.3	4,172	91.1	6,275	89.4
1-50	83	0.4	83	0.8	0	0.0	6	0.1	70	1.0
51-100	106	0.5	106	1.1	–	–	3	0.1	97	1.4
101-150	72	0.3	72	0.7	–	–	4	0.1	67	1.0
151-200	105	0.5	105	1.1	0	0.0	6	0.1	99	1.4
201-250	77	0.3	77	0.8	–	–	4	0.1	75	1.1
251-300	58	0.3	58	0.6	0	0.0	5	0.1	58	0.8
301-350	55	0.2	55	0.6	–	–	5	0.1	51	0.7
351-400	36	0.2	36	0.4	–	–	2	0.0	34	0.5
401+	192	0.9	192	2.0	–	–	23	0.5	177	2.5
Not applicable[d]	744	3.3	25	0.3	371	8.7	350	7.6	13	0.2
Medical deduction										
$0	20,580	91.7	9,650	98.6	3,171	74.5	3,798	82.9	6,906	98.4
1-50	109	0.5	9	0.1	55	1.3	57	1.2	10	0.1
51-100	440	2.0	48	0.5	277	6.5	171	3.7	37	0.5
101-150	200	0.9	26	0.3	113	2.7	91	2.0	17	0.2
151-200	134	0.6	15	0.2	103	2.4	38	0.8	9	0.1
201-250	90	0.4	5	0.0	67	1.6	25	0.5	7	0.1
251-300	29	0.1	3	0.0	21	0.5	8	0.2	1	0.0
301+	118	0.5	7	0.1	78	1.8	41	0.9	15	0.2
Not applicable[d]	744	3.3	25	0.3	371	8.7	350	7.6	13	0.2
Child support deduction										
$0	21,285	94.8	9,563	97.7	3,847	90.4	4,100	89.5	6,777	96.6
1-50	62	0.3	21	0.2	8	0.2	25	0.5	21	0.3
51-100	59	0.3	30	0.3	6	0.1	23	0.5	28	0.4
101-150	45	0.2	18	0.2	9	0.2	13	0.3	21	0.3
151-200	59	0.3	30	0.3	5	0.1	12	0.3	37	0.5
201-250	37	0.2	15	0.2	2	0.0	13	0.3	18	0.3
251-300	32	0.1	15	0.2	2	0.1	13	0.3	19	0.3
301-350	39	0.2	23	0.2	1	0.0	8	0.2	30	0.4

See footnotes at end of table.

Table A.11. Distribution of participating households by selected household characteristics and amount of deduction — Continued

Household characteristic	Total households		Households with:							
			Children		Elderly individuals		Non-elderly individuals with disabilities		Countable earned income	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Child support deduction										
351-400	23	0.1	9	0.1	3	0.1	7	0.2	12	0.2
401+	60	0.3	38	0.4	2	0.0	13	0.3	40	0.6
Not applicable[e]	744	3.3	25	0.3	371	8.7	350	7.6	13	0.2
Excess shelter deduction										
$0	5,697	25.4	2,094	21.4	720	16.9	660	14.4	1,164	16.6
1-50	693	3.1	291	3.0	140	3.3	164	3.6	200	2.9
51-100	639	2.8	299	3.1	171	4.0	212	4.6	217	3.1
101-150	730	3.3	353	3.6	196	4.6	223	4.9	280	4.0
151-200	852	3.8	386	3.9	219	5.1	256	5.6	298	4.2
201-250	917	4.1	392	4.0	234	5.5	264	5.8	322	4.6
251-300	1,076	4.8	496	5.1	250	5.9	306	6.7	376	5.4
301-350	1,207	5.4	529	5.4	247	5.8	306	6.7	415	5.9
351-400	1,356	6.0	572	5.8	253	5.9	260	5.7	434	6.2
401-477	1,810	8.1	804	8.2	366	8.6	388	8.5	630	9.0
478	4,465	19.9	3,107	31.7	5	0.1	2	0.0	2,406	34.3
479-500	190	0.8	40	0.4	86	2.0	105	2.3	19	0.3
501-550	423	1.9	57	0.6	179	4.2	245	5.4	38	0.5
551-600	363	1.6	63	0.6	167	3.9	194	4.2	41	0.6
601+	1,437	6.4	280	2.9	720	16.9	732	16.0	163	2.3
Not applicable[e]	589	2.6	25	0.3	305	7.2	261	5.7	13	0.2
No deduction	5,697	25.4	2,094	21.4	720	16.9	660	14.4	1,164	16.6
Deduction less than cap[f]	9,291	41.4	4,126	42.2	2,077	48.8	2,381	52.0	3,176	45.3
Deduction equal to cap	4,474	19.9	3,114	31.8	4	0.1	2	0.0	2,411	34.4
Benefit less than maximum benefit	1,915	8.5	1,578	16.1	4	0.1	2	0.0	1,563	22.3
Benefit equal to maximum benefit	2,559	11.4	1,535	15.7	–	–	–	–	848	12.1
Deduction greater than cap	2,394	10.7	430	4.4	1,149	27.0	1,275	27.8	252	3.6
Not applicable[e]	589	2.6	25	0.3	305	7.2	261	5.7	13	0.2

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] This row contains MFIP households, which do not receive a standard deduction, and households in the Virgin Islands, which receive a standard deduction of $134 for one-, two-person households, and $135 for three-person households.

[b] Deductions are not used in the benefit determinations of SSI-CAP households in States that use standardized SSI-CAP benefits.

[c] This deduction is not used in the benefit determinations of SSI-CAP households.

[d] This deduction is not used in the benefit determinations of MFIP households or SSI-CAP households.

[e] This deduction is not used in the benefit determinations of MFIP households or SSI-CAP households in States that use standardized SSI-CAP benefits.

[f] Households without elderly or disabled members are subject to a cap on their excess shelter deduction.

– No sample households in this category.

Table A.12. Distribution of participating households by selected household characteristics and SNAP benefit amount, SNAP benefit as a percentage of the maximum benefit, and certification period

Household characteristic	Total households		Households with:									
			Children		Elderly individuals		Non-elderly individuals with disabilities		Countable earned income		Countable TANF income	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total	22,445	100.0	9,789	100.0	4,255	100.0	4,579	100.0	7,016	100.0	1,362	100.0
SNAP benefit												
Minimum benefit or less[a]	1,456	6.5	133	1.4	746	17.5	472	10.3	344	4.9	8	0.6
Greater than the minimum-$50	936	4.2	105	1.1	373	8.8	401	8.8	186	2.6	10	0.8
51-100	1,775	7.9	279	2.8	721	17.0	700	15.3	394	5.6	21	1.5
101-188	3,390	15.1	794	8.1	1,054	24.8	1,216	26.6	1,099	15.7	69	5.1
189	5,346	23.8	297	3.0	874	20.5	465	10.2	721	10.3	63	4.6
190-300	2,229	9.9	1,430	14.6	250	5.9	433	9.5	1,155	16.5	161	11.8
301-400	3,184	14.2	2,717	27.8	163	3.8	403	8.8	1,319	18.8	420	30.8
401-500	1,980	8.8	1,900	19.4	36	0.8	223	4.9	872	12.4	299	21.9
501-600	678	3.0	669	6.8	10	0.2	114	2.5	382	5.4	113	8.3
601+	1,471	6.6	1,463	14.9	28	0.6	152	3.3	543	7.7	198	14.6
Benefit as a percentage of the maximum												
Minimum	1,433	6.4	118	1.2	741	17.4	460	10.1	334	4.8	5	0.4
< 25%[b]	1,392	6.2	526	5.4	417	9.8	540	11.8	510	7.3	34	2.5
25-50%	2,908	13.0	1,366	14.0	778	18.3	936	20.4	1,283	18.3	95	7.0
51-75%	3,451	15.4	1,897	19.4	716	16.8	1,055	23.0	1,625	23.2	193	14.2
76-99%	3,846	17.1	2,380	24.3	531	12.5	895	19.6	1,661	23.7	518	38.0
Maximum	9,414	41.9	3,501	35.8	1,073	25.2	693	15.1	1,602	22.8	517	37.9
Months in certification period												
Average[c]	13	–	10	–	19	–	17	–	10	–	11	–
Median[d]	12	–	12	–	12	–	12	–	12	–	12	–
1-5	386	1.7	216	2.2	21	0.5	40	0.9	148	2.1	31	2.3
6	6,004	26.8	3,544	36.2	338	7.9	618	13.5	2,552	36.4	242	17.8
7-11	536	2.4	302	3.1	48	1.1	82	1.8	169	2.4	103	7.6
12	11,673	52.0	5,496	56.1	1,821	42.8	2,233	48.8	3,968	56.6	940	69.0
13-23	207	0.9	72	0.7	52	1.2	58	1.3	50	0.7	14	1.0
24	2,515	11.2	135	1.4	1,346	31.6	1,108	24.2	113	1.6	28	2.0
25-35	72	0.3	7	0.1	35	0.8	38	0.8	2	0.0	2	0.2
36	633	2.8	10	0.1	360	8.5	234	5.1	2	0.0	1	0.1
37+	398	1.8	0	0.0	234	5.5	164	3.6	3	0.0	0	0.0
Unknown	21	0.1	7	0.1	1	0.0	5	0.1	8	0.1	2	0.1

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] The minimum benefit, applicable to one- and two-person households, is equal to 8 percent of the maximum benefit for single-person households. See Table C.6 for the fiscal year 2014 minimum benefit values.

[b] Does not include households with the minimum benefit.

[c] Average number of months in certification period. Percent not applicable in this row.

[d] Median number of months in certification period. Percent not applicable in this row.

– Not applicable.

Table A.13. Distribution of participating households by type of most recent action and expedited service

Most recent action and expedited service	Total households		Entrants		Other households	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total	22,445	100.0	872	100.0	21,573	100.0
Initial certification	8,513	37.9	872	100.0	7,641	35.4
Eligible for and receiving expedited service	2,610	11.6	429	49.2	2,181	10.1
Eligible for but did not receive expedited service	638	2.8	56	6.5	582	2.7
Not eligible for expedited service	5,264	23.5	386	44.3	4,878	22.6
Recertification	13,932	62.1	–	–	13,932	64.6
Eligible for and receiving expedited service	171	0.8	–	–	171	0.8
Eligible for but did not receive expedited service	51	0.2	–	–	51	0.2
Not eligible for expedited service	13,710	61.1	–	–	13,710	63.6

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

– By definition these are mutually exclusive categories.

Table A.14. Distribution of participating households, individuals, and benefits by household composition

Household composition	SNAP households		Participants in households with household characteristic		Monthly SNAP benefits	
	Number (000)	Percent	Number (000)	Percent	Dollars (000)	Percent
Total[a]	22,445	100.0	45,874	100.0	5,689,647	100.0
Children, elderly individuals, or individuals with disabilites	16,970	75.6	39,858	86.9	4,677,230	82.2
Children[b]	9,789	43.6	31,609	68.9	3,817,969	67.1
Single-adult household	5,591	24.9	16,448	35.9	2,093,882	36.8
Male adult	454	2.0	1,198	2.6	158,551	2.8
Female adult	5,137	22.9	15,250	33.2	1,935,331	34.0
Multiple-adult household	2,834	12.6	12,144	26.5	1,294,839	22.8
Married-head household	1,788	8.0	7,826	17.1	810,746	14.2
Other multiple-adult household	1,047	4.7	4,318	9.4	484,093	8.5
Children only	1,363	6.1	3,017	6.6	429,247	7.5
Elderly individuals	4,255	19.0	5,359	11.7	548,607	9.6
Living alone	3,473	15.5	3,473	7.6	382,681	6.7
Living with only elderly individuals	360	1.6	721	1.6	57,744	1.0
Living with at least one non-elderly individual	422	1.9	1,165	2.5	108,182	1.9
Non-elderly individuals with disabilities	4,579	20.4	8,681	18.9	858,511	15.1
Living alone	2,760	12.3	2,760	6.0	298,210	5.2
Not living alone	1,819	8.1	5,921	12.9	560,302	9.8
Other households[c]	5,475	24.4	6,016	13.1	1,012,418	17.8
Single-person household	5,028	22.4	5,028	11.0	876,782	15.4
Multiperson household	447	2.0	988	2.2	135,636	2.4
Adults age 18 to 49 without disabilities in childless households[d]	4,333	19.3	5,189	11.3	829,307	14.6
Single-person household	3,670	16.3	3,670	8.0	638,734	11.2
Multiperson household	663	3.0	1,519	3.3	190,573	3.3
Single-person households	11,670	52.0	11,670	25.4	1,630,265	28.7

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] The sum of individual categories does not match the table total because a household may have more than one of the characteristics in the table.

[b] Individuals with missing age were assigned child or adult status based on their relationship to the household head.

[c] Households not containing children, elderly individuals, or non-elderly individuals with disabilities.

[d] With some exceptions, these participants are subject to work requirements and a time limit.

Table A.15. Average gross countable income as a percentage of poverty guideline, gross and net countable income, total deduction, SNAP benefit, household size, and certification period of participating households by household composition

Household composition	Total households		Average values						
	Number (000)	Percent	Gross countable income as a percentage of poverty guideline (percent)	Gross countable income (dollars)	Net countable income (dollars)[a]	Total deduction (dollars)[b]	SNAP benefit (dollars)	Household size (individuals)	Certification period (months)
Total[c]	22,445	100.0	57.8	759	335	538	253	2.0	12.9
Children, elderly individuals, or individuals with disabilities	16,970	75.6	68.3	921	420	584	276	2.3	13.9
Children[d]	9,789	43.6	56.0	965	449	615	390	3.2	9.8
Single-adult household	5,591	24.9	52.6	841	373	571	375	2.9	9.9
Male adult	454	2.0	50.4	765	319	572	349	2.6	10.1
Female adult	5,137	22.9	52.8	847	378	570	377	3.0	9.9
Multiple-adult household	2,834	12.6	65.1	1,336	715	698	457	4.3	9.7
Married-head household	1,788	8.0	68.5	1,426	768	733	454	4.4	9.6
Other multiple-adult household	1,047	4.7	59.4	1,184	624	639	463	4.1	9.9
Children only	1,363	6.1	51.2	706	207	621	315	2.2	9.4
Elderly individuals	4,255	19.0	83.7	876	407	544	129	1.3	19.5
Living alone	3,473	15.5	82.5	791	332	530	110	1.0	20.6
Living with only elderly individuals	360	1.6	99.0	1,282	711	609	160	2.0	17.5
Living with at least one non-elderly individual	422	1.9	80.8	1,228	705	595	256	2.8	11.7
Non-elderly individuals with disabilities	4,579	20.4	82.4	1,006	501	543	187	1.9	16.7
Living alone	2,760	12.3	86.3	828	322	532	108	1.0	20.1
Not living alone	1,819	8.1	76.5	1,277	746	559	308	3.3	11.5
Other households[e]	5,475	24.4	25.3	259	83	400	185	1.1	9.8
Single-person household	5,028	22.4	23.1	221	66	384	174	1.0	9.9
Multiperson household	447	2.0	50.3	687	271	572	304	2.2	9.6
Adults age 18 to 49 without disabilities in childless households[f]	4,333	19.3	28.7	314	113	410	191	1.2	9.8
Single-person household	3,670	16.3	23.1	221	66	380	174	1.0	9.7
Multiperson household	663	3.0	59.5	828	368	575	287	2.3	10.3
Single-person households	11,670	52.0	56.4	542	199	466	140	1.0	15.5

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Because net income is not used in their benefit determinations, 23,481 MFIP households and 565,481 SSI-CAP households in States that use standardized SSI-CAP benefits are excluded from this column. Thus, the average values are based on fewer households than the number shown in the Total Households column.

[b] Because deductions are not used in their benefit determinations, 565,481 SSI-CAP households in States that use standardized SSI-CAP benefits are excluded from this column. Thus, the average values are based on fewer households than the number shown in the Total Households column.

[c] The sum of individual categories does not match the table total because a household may have more than one of the characteristics in the table.

[d] Individuals with missing age were assigned child or adult status based on their relationship to the household head.

[e] Households not containing children, elderly individuals, or non-elderly individuals with disabilities.

[f] With some exceptions, these participants are subject to work requirements and a time limit.

Table A.16. Distribution of participating households by countable income type and household composition

Household composition	Total households		Countable income type											
	Number (000)	Percent	Earned income		Zero gross income		TANF income		GA income		SSI		Social Security income	
			Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total[a]	22,445	100.0	7,016	100.0	4,919	100.0	1,362	100.0	694	100.0	4,568	100.0	5,505	100.0
Children, elderly individuals, or individuals with disabilities	16,970	75.6	5,568	79.4	1,680	34.2	1,321	96.9	390	56.2	4,568	100.0	5,444	98.9
Children[b]	9,789	43.6	5,113	72.9	1,376	28.0	1,313	96.4	142	20.5	1,125	24.6	871	15.8
Single-adult household	5,591	24.9	2,327	33.2	963	19.6	877	64.4	92	13.2	681	14.9	528	9.6
Male adult	454	2.0	168	2.4	111	2.3	75	5.5	10	1.4	48	1.0	68	1.2
Female adult	5,137	22.9	2,159	30.8	852	17.3	803	58.9	82	11.8	633	13.9	460	8.4
Multiple-adult household	2,834	12.6	1,817	25.9	285	5.8	247	18.1	33	4.8	385	8.4	332	6.0
Married-head household	1,788	8.0	1,236	17.6	178	3.6	124	9.1	18	2.6	185	4.1	177	3.2
Other multiple-adult household	1,047	4.7	581	8.3	107	2.2	123	9.0	15	2.2	200	4.4	154	2.8
Children only	1,363	6.1	969	13.8	128	2.6	188	13.8	18	2.5	60	1.3	11	0.2
Elderly individuals	4,255	19.0	291	4.2	308	6.3	37	2.7	159	22.9	1,556	34.1	2,914	52.9
Living alone	3,473	15.5	162	2.3	288	5.8	1	0.1	127	18.3	1,263	27.6	2,379	43.2
Living with only elderly individuals	360	1.6	38	0.5	8	0.2	0	0.0	19	2.7	136	3.0	262	4.8
Living with at least one non-elderly individual	422	1.9	92	1.3	12	0.2	35	2.6	14	1.9	157	3.4	274	5.0
Non-elderly individuals with disabilities	4,579	20.4	518	7.4	0	0.0	245	18.0	152	22.0	3,101	67.9	2,354	42.8
Living alone	2,760	12.3	144	2.1	0	0.0	2	0.1	79	11.4	1,734	37.9	1,561	28.4
Not living alone	1,819	8.1	373	5.3	–	–	244	17.9	73	10.5	1,367	29.9	793	14.4
Other households[c]	5,475	24.4	1,448	20.6	3,239	65.8	42	3.1	304	43.8	0	0.0	60	1.1
Single-person household	5,028	22.4	1,208	17.2	3,107	63.2	32	2.3	288	41.5	0	0.0	44	0.8
Multiperson household	447	2.0	240	3.4	131	2.7	10	0.7	16	2.4	–	–	16	0.3
Adults age 18 to 49 without disabilities in childless households[d]	4,333	19.3	1,183	16.9	2,416	49.1	43	3.2	206	29.7	138	3.0	194	3.5
Single-person household	3,670	16.3	916	13.0	2,290	46.6	30	2.2	188	27.1	0	0.0	24	0.4
Multiperson household	663	3.0	268	3.8	126	2.6	14	1.0	18	2.6	138	3.0	171	3.1
Single-person households	11,670	52.0	1,779	25.4	3,447	70.1	99	7.3	504	72.6	2,998	65.6	3,989	72.5

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] The sum of individual categories does not match the table total because a household may have more than one of the characteristics in the table.

[b] Individuals with missing age were assigned child or adult status based on their relationship to the household head.

[c] Households not containing children, elderly individuals, or non-elderly individuals with disabilities.

[d] With some exceptions, these participants are subject to work requirements and a time limit.

– No sample households in this category.

Table A.17. Distribution of participating households with children, elderly individuals, and non-elderly individuals with disabilities by selected characteristics

Household characteristic	Total households		Households with:									
	Number (000)	Percent	Children		School-age children		Preschool-age children		Elderly individuals		Non-elderly individuals with disabilities	
			Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total	22,445	100.0	9,789	100.0	7,603	100.0	4,869	100.0	4,255	100.0	4,579	100.0
Household composition												
Children	9,789	43.6	9,789	100.0	7,603	100.0	4,869	100.0	190	4.5	1,376	30.1
School-age	7,603	33.9	7,603	77.7	7,603	100.0	2,684	55.1	173	4.1	1,211	26.4
Preschool-age	4,869	21.7	4,869	49.7	2,684	35.3	4,869	100.0	32	0.8	500	10.9
Elderly individuals	4,255	19.0	190	1.9	173	2.3	32	0.7	4,255	100.0	128	2.8
Non-elderly individuals with disabilities	4,579	20.4	1,376	14.1	1,211	15.9	500	10.3	128	3.0	4,579	100.0
Countable income source and resources												
Gross income	17,526	78.1	8,412	85.9	6,656	87.5	4,121	84.6	3,947	92.8	4,579	100.0
No gross income	4,919	21.9	1,376	14.1	947	12.5	748	15.4	308	7.2	0	0.0
Net income	12,745	56.8	6,264	64.0	5,091	67.0	3,025	62.1	3,034	71.3	3,772	82.4
No net income	9,111	40.6	3,500	35.8	2,495	32.8	1,831	37.6	917	21.6	546	11.9
Not applicable[a]	589	2.6	25	0.3	17	0.2	13	0.3	305	7.2	261	5.7
Earned income	7,016	31.3	5,113	52.2	3,993	52.5	2,689	55.2	291	6.8	518	11.3
Unearned income	12,646	56.3	4,970	50.8	4,062	53.4	2,258	46.4	3,817	89.7	4,577	99.9
TANF income	1,362	6.1	1,313	13.4	950	12.5	699	14.4	37	0.9	245	5.4
GA income	694	3.1	142	1.5	119	1.6	57	1.2	159	3.7	152	3.3
SSI	4,568	20.4	1,125	11.5	999	13.1	406	8.3	1,556	36.6	3,101	67.7
Social Security income	5,505	24.5	871	8.9	780	10.3	276	5.7	2,914	68.5	2,354	51.4
Countable resources	1,141	5.1	570	5.8	449	5.9	279	5.7	270	6.3	250	5.5
Deductions												
Total deduction	21,862	97.4	9,770	99.8	7,590	99.8	4,861	99.8	3,951	92.8	4,318	94.3
Standard deduction	21,856	97.4	9,764	99.7	7,587	99.8	4,856	99.7	3,951	92.8	4,318	94.3
Earned income deduction	6,993	31.2	5,110	52.2	3,992	52.5	2,687	55.2	290	6.8	504	11.0
Dependent care deduction	784	3.5	783	8.0	529	7.0	537	11.0	1	0.0	58	1.3
Excess shelter deduction	16,159	72.0	7,669	78.4	6,037	79.4	3,738	76.8	3,231	75.9	3,659	79.9
Medical deduction	1,121	5.0	114	1.2	102	1.3	32	0.7	714	16.8	431	9.4
Child support deduction	416	1.9	200	2.0	164	2.2	94	1.9	38	0.9	129	2.8
SNAP benefit												
Minimum benefit or less[b]	1,456	6.5	133	1.4	100	1.3	40	0.8	746	17.5	472	10.3
Greater than the minimum-$100	2,710	12.1	384	3.9	307	4.0	126	2.6	1,095	25.7	1,102	24.1
101-200	9,409	41.9	1,244	12.7	882	11.6	526	10.8	2,029	47.7	1,774	38.7
201-300	1,557	6.9	1,278	13.1	969	12.7	577	11.8	149	3.5	340	7.4
301+	7,312	32.6	6,750	69.0	5,346	70.3	3,601	74.0	236	5.6	892	19.5
Minimum benefit	1,433	6.4	118	1.2	85	1.1	37	0.8	741	17.4	460	10.1
Maximum benefit	9,414	41.9	3,501	35.8	2,497	32.8	1,831	37.6	1,073	25.2	693	15.1
Household size												
1	11,670	52.0	416	4.2	245	3.2	171	3.5	3,473	81.6	2,760	60.3
2	4,221	18.8	2,995	30.6	1,874	24.6	1,341	27.5	617	14.5	736	16.1
3	3,020	13.5	2,870	29.3	2,234	29.4	1,383	28.4	88	2.1	450	9.8
4	1,927	8.6	1,905	19.5	1,685	22.2	987	20.3	39	0.9	315	6.9
5	1,006	4.5	1,002	10.2	968	12.7	584	12.0	16	0.4	175	3.8
6+	602	2.7	602	6.1	598	7.9	403	8.3	23	0.5	144	3.1

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Net income is not used in the benefit determinations of MFIP households or SSI-CAP households in States that use standardized SSI-CAP benefits.

[b] The minimum benefit, applicable to one- and two-person households, is equal to 8 percent of the maximum benefit for single-person households. See Table C.6 for the fiscal year 2014 minimum benefit values.

Table A.18. Average values of selected characteristics for participating households with children, elderly individuals, and non-elderly individuals with disabilities

Household characteristic	Average values	Average values for households with: Children	School-age children	Preschool-age children	Elderly individuals	Non-elderly individuals with disabilities
Countable income (dollars)						
Gross income	759	965	1,025	955	876	1,006
Net income[a]	335	449	495	427	407	501
Earned income	332	628	650	674	51	89
Unearned income	427	338	376	282	825	917
TANF income	23	52	49	58	2	17
GA income	7	5	6	4	8	4
SSI	120	88	103	65	179	440
Social Security income	201	68	79	42	583	413
Countable income as a percentage of poverty guideline (percent)						
Gross income	57.8	56.0	57.3	53.6	83.7	82.4
Net income[a]	23.5	24.8	26.5	22.5	35.0	35.7
Deductions (dollars)						
Total deduction[b]	538	615	622	629	544	543
Earned income deduction						
All households[c]	69	125	130	135	11	19
Households with deduction	213	240	247	244	151	161
Dependent care deduction						
All households[d]	10	22	19	32	0	5
Households with deduction	276	276	268	287	184	356
Excess shelter deduction						
All households[e]	290	298	302	293	350	342
Households with deduction	393	380	379	381	428	404
Medical deduction						
All households[d]	8	2	2	1	29	15
Households with deduction	155	137	138	132	160	145
Child support deduction						
All households[e]	4	5	6	5	2	6
Households with deduction	229	250	258	240	163	196
SNAP benefit (dollars)	253	390	407	420	129	187
Household size (individuals)	2.0	3.2	3.4	3.4	1.3	1.9
Certification period (months)	12.9	9.8	9.8	9.6	19.5	16.7

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Because net income is not used in their benefit determination, 23,481 MFIP households and 565,481 SSI-CAP households are excluded from this category.

[b] Because deductions are not used in their benefit determination, 565,481 SSI-CAP households are excluded from this category.

[c] Because this deduction is not used in their benefit determination, 720,552 SSI-CAP households are excluded from this category.

[d] Because this deduction is not used in their benefit determination, 23,481 MFIP households and 720,552 SSI-CAP households are excluded from this category.

[e] Because this deduction is not used in their benefit determination, 23,481 MFIP households and 565,481 SSI-CAP households are excluded from this category.

Table A.19. Distribution of participating households with countable earned and unearned income by selected characteristics

Household characteristic	Total households		Countable income type							
			Earned income		Unearned income		TANF income		GA income	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total	22,445	100.0	7,016	100.0	12,646	100.0	1,362	100.0	694	100.0
Household composition										
Children	9,789	43.6	5,113	72.9	4,970	39.3	1,313	96.4	142	20.5
School-age	7,603	33.9	3,993	56.9	4,062	32.1	950	69.7	119	17.2
Preschool-age	4,869	21.7	2,689	38.3	2,258	17.9	699	51.3	57	8.2
Elderly individuals	4,255	19.0	291	4.2	3,817	30.2	37	2.7	159	22.9
Non-elderly individuals with disabilities	4,579	20.4	518	7.4	4,577	36.2	245	18.0	152	22.0
Countable income source										
Gross income	17,526	78.1	7,016	100.0	12,646	100.0	1,362	100.0	694	100.0
No gross income[a]	4,919	21.9	–	–	–	–	–	–	–	–
Net income	12,745	56.8	5,405	77.0	9,225	72.9	826	60.6	318	45.8
No net income	9,111	40.6	1,597	22.8	2,835	22.4	517	37.9	369	53.2
Not applicable[b]	589	2.6	13	0.2	587	4.6	20	1.4	7	0.9
Earned income	7,016	31.3	7,016	100.0	2,136	16.9	308	22.6	61	8.8
Unearned income	12,646	56.3	2,136	30.4	12,646	100.0	1,362	100.0	694	100.0
TANF income	1,362	6.1	308	4.4	1,362	10.8	1,362	100.0	9	1.3
GA income	694	3.1	61	0.9	694	5.5	9	0.7	694	100.0
SSI	4,568	20.4	405	5.8	4,568	36.1	234	17.2	205	29.6
Social Security income	5,505	24.5	407	5.8	5,505	43.5	100	7.3	119	17.2
Deductions										
Total deduction	21,862	97.4	7,009	99.9	12,064	95.4	1,346	98.8	688	99.1
Standard deduction	21,856	97.4	7,003	99.8	12,060	95.4	1,343	98.6	687	99.1
Earned income deduction	6,993	31.2	6,993	99.7	2,119	16.8	307	22.6	61	8.7
Dependent care deduction	784	3.5	728	10.4	308	2.4	27	2.0	3	0.4
Excess shelter deduction	16,159	72.0	5,839	83.2	10,118	80.0	1,119	82.1	587	84.5
Medical deduction	1,121	5.0	97	1.4	1,113	8.8	8	0.6	7	1.0
Child support deduction	416	1.9	226	3.2	239	1.9	4	0.3	6	0.9
SNAP benefit										
Minimum benefit or less[c]	1,456	6.5	344	4.9	1,284	10.2	8	0.6	26	3.8
Greater than the minimum-$100	2,710	12.1	580	8.3	2,353	18.6	31	2.3	64	9.3
101-200	9,409	41.9	1,985	28.3	4,476	35.4	159	11.7	448	64.5
201-300	1,557	6.9	990	14.1	900	7.1	134	9.8	34	4.9
301+	7,312	32.6	3,117	44.4	3,632	28.7	1,030	75.6	121	17.4
Minimum benefit	1,433	6.4	334	4.8	1,266	10.0	5	0.4	26	3.8
Maximum benefit	9,414	41.9	1,602	22.8	3,138	24.8	517	37.9	376	54.1
Household size										
1	11,670	52.0	1,779	25.4	6,791	53.7	99	7.3	504	72.6
2	4,221	18.8	1,649	23.5	2,374	18.8	478	35.1	96	13.9
3	3,020	13.5	1,531	21.8	1,623	12.8	390	28.7	40	5.8
4	1,927	8.6	1,070	15.3	1,021	8.1	220	16.2	26	3.7
5	1,006	4.5	621	8.9	506	4.0	98	7.2	17	2.5
6+	602	2.7	366	5.2	331	2.6	77	5.6	10	1.5

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Some States allow child support expenses to be subtracted before gross income is calculated. As a result, it is possible to have countable income but no gross income.

[b] Net income is not used in the benefit determinations of MFIP households or SSI-CAP households in States that use standardized SSI-CAP benefits.

[c] The minimum benefit, applicable to one- and two-person households, is equal to 8 percent of the maximum benefit for single-person households. See Table C.6 for the fiscal year 2014 minimum benefit values.

– No sample households in this category.

Table A.20. Average values of selected characteristics for participating households with countable earned and unearned income

Household characteristic	Average values	Average values for households with countable:			
		Earned income	Unearned income	TANF income	GA income
Countable income (dollars)					
Gross income	759	1,221	914	737	594
Net income[a]	335	544	424	292	212
Earned income	332	1,064	157	164	76
Unearned income	427	158	758	573	517
TANF income	23	14	41	383	4
GA income	7	2	12	1	225
SSI	120	36	213	129	175
Social Security income	201	42	357	37	98
Countable income as a percentage of poverty guideline (percent)					
Gross income	57.8	78.9	74.0	44.7	49.6
Net income[a]	23.5	32.9	30.9	16.0	15.4
Deductions (dollars)					
Total deduction[b]	538	728	547	516	537
Earned income deduction					
All households[c]	69	213	33	33	16
Households with deduction	213	213	187	146	175
Dependent care deduction					
All households[d]	10	29	8	6	1
Households with deduction	276	277	308	300	316
Excess shelter deduction					
All households[e]	290	315	332	320	360
Households with deduction	393	378	395	384	422
Medical deduction					
All households[d]	8	3	14	1	1
Households with deduction	155	190	155	154	89
Child support deduction					
All households[e]	4	8	4	0	1
Households with deduction	229	253	209	167	105
SNAP benefit (dollars)	253	298	225	407	215
Household size (individuals)	2.0	2.8	2.0	3.0	1.6
Certification period (months)	12.9	9.8	15.3	10.9	13.7

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Because net income is not used in their benefit determination, 23,481 MFIP households and 565,481 SSI-CAP households are excluded from this category.

[b] Because deductions are not used in their benefit determination, 565,481 SSI-CAP households are excluded from this category.

[c] Because this deduction is not used in their benefit determination, 720,552 SSI-CAP households are excluded from this category.

[d] Because this deduction is not used in their benefit determination, 23,481 MFIP households and 720,552 SSI-CAP households are excluded from this category.

[e] Because this deduction is not used in their benefit determination, 23,481 MFIP households and 565,481 SSI-CAP households are excluded from this category.

Table A.21. Distribution of participating households with selected household characteristics by race/Hispanic status of household head

Characteristic	Total households		Households with:									
			Children		Elderly individuals		Non-elderly individuals with disabilities		Countable earned income		Countable TANF income	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total	22,445	100.0	9,789	100.0	4,255	100.0	4,579	100.0	7,016	100.0	1,362	100.0
Race and Hispanic status[a] of household head												
White, not Hispanic	8,940	39.8	3,300	33.7	1,776	41.7	2,148	46.9	2,512	35.8	357	26.2
African American, not Hispanic	5,717	25.5	2,306	23.6	909	21.4	1,290	28.2	1,489	21.2	405	29.7
Hispanic, any race	2,448	10.9	1,098	11.2	591	13.9	311	6.8	827	11.8	214	15.7
Asian, not Hispanic	550	2.4	206	2.1	233	5.5	53	1.2	174	2.5	31	2.2
Native American, not Hispanic	229	1.0	104	1.1	32	0.8	39	0.9	58	0.8	17	1.2
Multiple races reported, not Hispanic	159	0.7	67	0.7	47	1.1	41	0.9	55	0.8	12	0.9
Race unknown	2,838	12.6	1,185	12.1	659	15.5	630	13.8	802	11.4	115	8.4
Nonparticipating household head[b]	1,565	7.0	1,522	15.5	9	0.2	67	1.5	1,098	15.7	213	15.6

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Codes to allow reporting of multiple races were implemented beginning in April 2007. We have grouped the codes together to form general race and ethnicity categories. “White, not Hispanic” includes “white, not Hispanic or Latino”; “African American, not Hispanic” includes “black or African American, not Hispanic or Latino” and “(black or African American) and white”; “Hispanic, any race” includes “Hispanic” and “(Hispanic or Latino) with any race or race combination”; “Asian, not Hispanic” includes “Asian,” “Native Hawaiian or other Pacific Islander,” and “Asian and white”; “Native American, not Hispanic” includes “American Indian or Alaska Native,” “(American Indian or Alaska Native) and white,” and “(American Indian or Alaska Native) and (black or African American)”; “Multiple races reported, not Hispanic” includes individuals who reported more than one race and who do not fit into any previously mentioned value; and “Race unknown” includes “Racial/ethnic data not available” and “Racial/ethnic data not recorded.” Reporting of race and ethnicity is now voluntary and was missing for 16 percent of participants in fiscal year 2014. As a result, fiscal year 2014 race and ethnicity distributions are not comparable to distributions for years prior to fiscal year 2007.

[b] This category includes some households with no household head and no adult listed on the file.

Table A.22. Distribution of participating households by presence of a household member with selected characteristics

Characteristic	Total households		Average value	Households with:									
				Children		Elderly individuals		Non-elderly individuals with disabilities		Countable earned income		Countable TANF income	
	Number (000)	Percent	SNAP benefit (dollars)	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total	22,445	100.0	253	9,789	100.0	4,255	100.0	4,579	100.0	7,016	100.0	1,362	100.0
Citizenship													
U.S.-born citizen	20,792	92.6	259	9,625	98.3	3,214	75.5	4,436	96.9	6,726	95.9	1,342	98.5
Naturalized citizen	1,384	6.2	252	489	5.0	707	16.6	137	3.0	395	5.6	47	3.4
Refugee	164	0.7	339	87	0.9	16	0.4	14	0.3	77	1.1	17	1.3
Other noncitizen	1,200	5.3	295	552	5.6	431	10.1	100	2.2	505	7.2	61	4.5
Citizen children living with participating noncitizen adults	483	2.2	447	483	4.9	25	0.6	42	0.9	332	4.7	55	4.1
Citizen children living with nonparticipating noncitizen adults	1,421	6.3	334	1,421	14.5	9	0.2	49	1.1	1,093	15.6	182	13.4

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

Table A.23. Gender and SNAP benefits of participants by selected demographic characteristics

Participant characteristic	Total participants		Female participants		Male participants		Prorated benefits[b]	
	Number (000)	Percent[a]	Number (000)	Percent[a]	Number (000)	Percent[a]	Dollars (000)	Percent
Total	45,874	100.0	25,762	56.2	20,112	43.8	5,689,647	100.0
Age								
Child	20,271	44.2	9,895	21.6	10,376	22.6	2,474,569	43.5
Preschool-age (4 or younger)	6,369	13.9	3,085	6.7	3,283	7.2	819,069	14.4
School-age (5 to 17)	13,902	30.3	6,810	14.8	7,093	15.5	1,655,501	29.1
Non-elderly adult	20,952	45.7	12,922	28.2	8,030	17.5	2,733,337	48.0
18 to 35	10,475	22.8	6,826	14.9	3,648	8.0	1,391,301	24.5
36 to 59	10,477	22.8	6,095	13.3	4,382	9.6	1,342,036	23.6
Elderly individual (60 or older)	4,651	10.1	2,945	6.4	1,705	3.7	481,674	8.5
Unknown age	0	0.0	0	0.0	–	–	67	0.0
Citizenship								
U.S.-born citizen	42,258	92.1	23,594	51.4	18,664	40.7	5,229,372	91.9
Naturalized citizen	1,715	3.7	1,094	2.4	621	1.4	213,921	3.8
Refugee	356	0.8	175	0.4	181	0.4	43,510	0.8
Other noncitizen	1,545	3.4	899	2.0	646	1.4	202,844	3.6
Citizen children living with noncitizen adults[c]	4,133	9.0	2,061	4.5	2,073	4.5	545,167	9.6
Non-elderly individuals with disabilities	5,467	11.9	2,966	6.5	2,501	5.5	537,236	9.4
Children with disabilities	1,006	2.2	398	0.9	608	1.3	90,267	1.6
Non-elderly adults with disabilities	4,461	9.7	2,568	5.6	1,893	4.1	446,970	7.9
Adults age 18 to 49 without disabilities in childless households[d]	4,721	10.3	2,102	4.6	2,619	5.7	775,692	13.6
Race and Hispanic status[e]								
White, not Hispanic	17,271	37.6	9,657	21.1	7,614	16.6	2,085,860	36.7
African American, not Hispanic	11,699	25.5	6,804	14.8	4,894	10.7	1,483,977	26.1
Hispanic, any race	7,525	16.4	4,122	9.0	3,403	7.4	987,772	17.4
Asian, not Hispanic	1,292	2.8	724	1.6	568	1.2	172,945	3.0
Native American, not Hispanic	546	1.2	296	0.6	251	0.5	69,847	1.2
Multiple races reported, not Hispanic	381	0.8	216	0.5	165	0.4	48,887	0.9
Race unknown	7,160	15.6	3,944	8.6	3,216	7.0	840,360	14.8

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Percent of all participants.

[b] Prorated benefits equal the benefits paid to households multiplied by the ratio of participants with selected characteristic to total household size.

[c] Noncitizens may be inside or outside the SNAP unit.

[d] With some exceptions, these participants are subject to work requirements and a time limit.

[e] Codes to allow reporting of multiple races were implemented beginning in April 2007. We have grouped the codes together to form general race and ethnicity categories. “White, not Hispanic” includes “white, not Hispanic or Latino”; “African American, not Hispanic” includes “black or African American, not Hispanic or Latino” and “(black or African American) and white”; “Hispanic, any race” includes “Hispanic” and “(Hispanic or Latino) with any race or race combination”; “Asian, not Hispanic” includes “Asian,” “Native Hawaiian or other Pacific Islander,” and “Asian and white”; “Native American, not Hispanic” includes “American Indian or Alaska Native,” “(American Indian or Alaska Native) and white,” and “(American Indian or Alaska Native) and (black or African American)”; “Multiple races reported, not Hispanic” includes individuals who reported more than one race and who do not fit into any previously mentioned value; and “Race unknown” includes “Racial/ethnic data not available” and “Racial/ethnic data not recorded.” Reporting of race and ethnicity is now voluntary and was missing for 16 percent of participants in fiscal year 2014. As a result, fiscal year 2014 race and ethnicity distributions are not comparable to distributions for years prior to fiscal year 2007.

– No sample participants in this category.

Table A.24. Distribution of participants by Thrifty Food Plan sex-age groups and household size

Participant characteristic	Household size								
	Total (000)	1	2	3	4	5	6	7	8+
Total	45,874	11,670	8,442	9,059	7,709	5,028	2,286	979	701
Children under age 12									
1 or younger	2,407	72	548	696	513	320	152	55	51
2 to 3 years	2,601	75	593	706	586	352	165	74	52
4 to 5 years	2,647	49	536	686	628	439	178	72	60
6 to 8 years	3,936	77	606	1,007	952	699	349	152	95
9 to 11 years	3,375	55	441	813	875	642	315	129	105
Females	25,762	6,153	5,240	5,353	4,320	2,641	1,192	506	358
1 or younger	1,137	40	257	327	241	139	76	28	29
2 to 3 years	1,258	30	278	366	282	155	83	39	27
4 to 5 years	1,317	29	256	342	328	209	90	36	28
6 to 8 years	1,925	37	320	497	461	329	154	81	47
9 to 11 years	1,654	22	216	417	439	303	154	54	49
12 to 13 years	957	21	125	233	265	166	88	36	25
14 to 18 years	1,957	76	332	464	470	325	151	85	53
19 to 50 years	10,503	2,232	2,472	2,468	1,743	973	380	142	93
51 to 70 years	3,735	2,559	798	224	87	38	15	6	7
71 and older	1,319	1,105	188	16	4	4	1	0	0
Males	20,112	5,517	3,202	3,706	3,389	2,387	1,095	473	342
1 or younger	1,270	32	291	369	272	181	77	27	21
2 to 3 years	1,343	45	315	340	305	197	82	35	25
4 to 5 years	1,330	20	280	345	300	230	88	37	31
6 to 8 years	2,011	40	287	510	490	370	195	72	48
9 to 11 years	1,721	32	225	396	437	339	160	75	56
12 to 13 years	991	11	112	257	237	187	100	53	34
14 to 18 years	2,020	40	338	566	493	302	140	77	64
19 to 50 years	5,998	2,931	630	770	768	529	227	88	55
51 to 70 years	2,824	2,020	487	141	86	50	25	9	8
71 and older	604	346	239	12	2	1	2	1	–

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

– No sample households in this category.

Table A.25. Distribution of household heads, all participants, and non-elderly adult participants by work registration status and employment status

Employment/work registration status	Household heads		All participants		Non-elderly adult participants	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total	22,445	100.0	45,874	100.0	20,952	100.0
Work registration status						
Work registrant	5,463	24.3	7,288	15.9	6,951	33.2
Mandatory Employment and Training program participant	2,322	10.3	2,970	6.5	2,944	14.1
Voluntary Employment and Training program participant	204	0.9	257	0.6	249	1.2
Not Employment and Training program participant	2,938	13.1	4,061	8.9	3,758	17.9
Exempt	15,411	68.7	38,566	84.1	13,996	66.8
For disability	5,924	26.4	7,050	15.4	4,641	22.2
For reason other than disability	9,487	42.3	31,517	68.7	9,354	44.6
Nonregistrant, should have registered	–	–	1	0.0	1	0.0
Nonparticipating household head[a]	1,565	7.0	–	–	–	–
Unknown	7	0.0	18	0.0	4	0.0
Employment and Training program status						
Total participating in Employment and Training program[b]	2,254	10.0	5,310	11.6	2,765	13.2
Not participating in Employment and Training program	18,622	83.0	40,556	88.4	18,184	86.8
Nonparticipating household head[a]	1,565	7.0	–	–	–	–
Unknown	4	0.0	8	0.0	3	0.0
Employment status						
Total employed	5,077	22.6	6,380	13.9	6,114	29.2
Self-employed, farming	8	0.0	16	0.0	14	0.1
Self-employed, nonfarming	536	2.4	713	1.6	656	3.1
Migrant farm labor	0	0.0	0	0.0	0	0.0
Non-migrant farm labor	2	0.0	4	0.0	4	0.0
Active-duty military service	2	0.0	2	0.0	2	0.0
Employed by other	4,528	20.2	5,644	12.3	5,439	26.0
Unemployed and looking for work	4,601	20.5	5,969	13.0	5,781	27.6
Not in labor force and not looking for work	11,201	49.9	33,522	73.1	9,055	43.2
Nonparticipating household head[a]	1,565	7.0	–	–	–	–
Unknown	2	0.0	2	0.0	1	0.0

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Household heads who are not participating with the household. Some household heads in this category are ineligible for SNAP or are in separate SNAP units not included in the SNAP QC sample. This category also includes some households with no adult listed on the file.

[b] Employment and Training may be provided through SNAP or another program.

– Not applicable.

Table A.26. Comparison of participating households with key SNAP household characteristics for fiscal years 1989 to 2014

		Percentage of households with:									
Time period	Total households (000)	Zero gross income	Zero net income[a]	Minimum benefit	Elderly individuals	Children	Non-elderly individuals with disabilities[b]	AFDC[c]/ TANF	Earnings	SSI	Any noncitizen
Fiscal year 1989.........	7,217	7.1	18.3	7.5	19.3	60.4	9.1	41.9	19.6	20.6	9.8
Fiscal year 1990.........	7,811	7.4	19.3	5.0	18.1	60.3	8.9	42.0	19.0	19.6	10.3
Fiscal year 1991.........	8,863	8.3	20.5	4.1	16.5	60.4	9.0	40.5	19.8	18.6	11.8
Fiscal year 1992.........	10,059	9.6	21.9	3.6	15.4	62.2	9.5	39.5	20.2	18.4	10.4
Fiscal year 1993.........	10,791	9.7	23.7	4.0	15.5	62.1	10.7	39.4	20.6	19.4	11.6
Fiscal year 1994.........	11,091	10.2	23.8	4.5	15.8	61.1	12.5	38.1	21.4	21.4	10.7
Fiscal year 1995.........	10,883	9.7	25.0	4.3	16.0	59.7	18.9	38.3	21.4	22.6	10.7
Fiscal year 1996.........	10,552	10.2	24.9	4.5	16.2	59.5	20.2	36.6	22.5	24.1	10.5
Fiscal year 1997.........	9,452	9.2	22.7	6.6	17.6	58.3	22.3	34.6	24.2	26.5	8.4
Fiscal year 1998.........	8,246	8.8	20.8	8.3	18.2	58.3	24.4	31.4	26.3	28.1	4.3
Fiscal year 1999.........	7,670	8.5	20.6	9.7	20.1	55.7	26.4	27.3	26.8	30.2	6.0
Fiscal year 2000.........	7,335	8.4	20.1	10.9	21.0	53.9	27.5	25.8	27.2	31.7	6.4
Fiscal year 2001.........	7,450	9.4	22.2	11.2	20.4	53.6	27.7	23.1	27.0	31.8	5.4
Fiscal year 2002.........	8,201	10.5	24.3	10.7	18.7	54.1	27.0	20.9	28.0	29.5	5.2
Fiscal year 2003.........	8,971	12.7	27.7	7.0	17.1	55.1	22.1	17.2	27.5	26.3	5.4
Fiscal year 2004.........	10,069	13.1	29.7	5.9	17.3	54.3	22.7	16.2	28.5	26.8	6.2
Fiscal year 2005.........	10,852	13.7	30.0	5.2	17.1	53.7	23.0	14.5	29.1	26.4	6.2
Fiscal year 2006.........	11,313	14.1	31.0	6.2	17.9	52.0	23.1	13.0	29.5	26.8	6.1
Fiscal year 2007.........	11,561	14.7	31.4	6.6	17.8	51.0	23.8	12.1	29.6	27.7	5.7
Fiscal year 2008.........	12,464	16.2	33.6	6.7	18.5	50.6	22.6	10.6	28.9	26.2	5.6
Fiscal year 2009.........	14,981	17.6	36.0	4.1	16.6	49.9	21.2	9.7	29.4	23.6	5.9
Fiscal year 2010.........	18,369	19.7	38.3	3.8	15.5	48.7	19.8	8.0	29.9	20.9	5.9
Fiscal year 2011.........	20,803	20.0	39.4	4.2	16.5	47.1	20.2	7.6	30.5	20.2	5.8
Fiscal year 2012.........	22,046	20.5	38.4	4.8	17.2	45.3	20.0	7.1	31.3	20.2	5.7
Fiscal year 2013.........	22,802	21.5	39.4	5.2	17.4	44.8	20.3	6.5	31.2	19.9	5.8
Fiscal year 2014.........	22,445	21.9	40.6	6.4	19.0	43.6	20.4	6.1	31.3	20.4	6.1

Source: Fiscal Years 1989 to 2014 Supplemental Nutrition Assistance Program Quality Control samples.

Note: Fiscal year analysis files were not developed for the years before 1989. The fiscal year 2003 through fiscal year 2014 estimates differ methodologically from estimates for earlier years and, in some cases, from estimates presented in reports prior to 2009. Under the current methodology, the weighting of the SNAP QC data reflects adjustments to FNS' Program Operations counts of households to account for receipt of benefits in error or for disaster assistance. In addition, the weighted SNAP QC data match adjusted Program Operations counts of households, individuals, and benefit amounts. Beginning with the fiscal year 2009 report, we also incorporated corrected SNAP Program Operations data from Missouri for every fiscal year from 2003 to 2008.

[a]Beginning in 2004, net income is not calculated for MFIP households or SSI-CAP households in States that use standardized SSI-CAP benefits.

[b]The substantial increase in 1995 and decrease in 2003 are in part a result of changes in the definition of a household with an individual with a disability. Prior to 1995, these households were defined as those with SSI and no members over age 59. In 1995, that definition changed to households with at least one member under age 65 who received SSI, or at least one member age 18 to 61 who received Social Security, veterans' benefits, or other government benefits as a result of a disability. Due to changes in the SNAP QC data in 2003, the definition changed again, to households with individuals under the age of 60 with SSI income, a medical expense deduction and without an elderly person, or with a non-elderly adult who worked fewer than 30 hours a week and received Social Security, veterans' benefits, or workers' compensation.

[c]Aid to Families with Dependent Children.

Table A.27. Comparison of average nominal and real values of key SNAP household characteristics for fiscal years 1989 to 2014

	Gross income (dollars)		Net income (dollars)[a]		Total deduction (dollars)[b]		SNAP benefit (dollars)			
Time period	Nominal value	Real value[c]	Nominal value	Real value[c]	Nominal value	Real value[c]	Nominal value	Real value[d]	Gross income as a percentage of poverty guidelines (percent)	Household size (individuals)
Fiscal year 1989………………..	442	841	247	470	216	411	132	252	60	2.6
Fiscal year 1990………………..	453	818	251	453	225	406	150	269	59	2.6
Fiscal year 1991………………..	464	804	253	438	235	407	162	283	58	2.6
Fiscal year 1992………………..	478	804	258	434	250	421	170	295	57	2.6
Fiscal year 1993………………..	490	800	258	421	262	428	170	288	56	2.6
Fiscal year 1994………………..	507	807	268	427	272	433	168	277	57	2.5
Fiscal year 1995………………..	514	796	265	410	283	438	172	274	56	2.5
Fiscal year 1996………………..	528	794	275	414	287	432	174	268	57	2.5
Fiscal year 1997………………..	558	821	299	440	291	428	169	254	58	2.4
Fiscal year 1998………………..	584	846	321	465	294	426	165	243	60	2.4
Fiscal year 1999………………..	603	854	338	479	299	424	162	234	62	2.4
Fiscal year 2000………………..	620	850	355	487	298	408	158	223	63	2.3
Fiscal year 2001………………..	624	832	353	470	311	414	163	223	62	2.3
Fiscal year 2002………………..	633	835	355	468	324	427	173	234	61	2.3
Fiscal year 2003………………..	608	780	317	407	346	444	192	254	57	2.3
Fiscal year 2004………………..	634	792	312	390	382	477	197	251	58	2.3
Fiscal year 2005………………..	644	778	316	382	390	471	209	261	58	2.3
Fiscal year 2006………………..	668	782	323	378	410	480	208	256	59	2.3
Fiscal year 2007………………..	684	779	325	370	430	489	212	250	59	2.2
Fiscal year 2008………………..	693	760	329	361	441	483	222	246	58	2.2
Fiscal year 2009………………..	711	782	329	362	471	518	272	300	58	2.2
Fiscal year 2010………………..	731	791	336	364	491	531	287	316	57	2.2
Fiscal year 2011………………..	744	787	338	358	508	537	281	299	59	2.1
Fiscal year 2012………………..	755	780	343	354	512	529	274	282	60	2.1
Fiscal year 2013………………..	758	770	344	350	522	530	271	276	59	2.1
Fiscal year 2014………………..	759	759	335	335	538	538	253	253	58	2.0

Sources: CPI-U values: U.S. Department of Labor, Bureau of Labor Statistics. Nominal values: Fiscal Years 1989 to 2014 Supplemental Nutrition Assistance Program Quality Control samples.

Note: The fiscal year 2003 through fiscal year 2014 estimates differ methodologically from estimates for earlier years and, in some cases, from estimates presented in reports prior to 2009. Under the current methodology, the weighting of the SNAP QC data reflects adjustments to FNS' Program Operations counts of households to account for receipt of benefits in error or for disaster assistance. In addition, the weighted SNAP QC data match adjusted Program Operations counts of households, individuals, and benefit amounts. Beginning with the fiscal year 2009 report, we also incorporated corrected SNAP Program Operations data from Missouri for every fiscal year from 2003 to 2008.

[a]Beginning in 2004, net income is not calculated for MFIP households or SSI-CAP households in States with standardized SSI-CAP benefit amounts.

[b]Some of the change in average total deductions and average net income between 2003 and 2004 may be attributable to two changes in the SNAP QC datafile development process. First, we revised the way certain deductions are calculated to correct for inconsistencies and data entry errors. Second, given that deductions are not used in their benefit determination, SSI-CAP participants in States that use standardized SSI-CAP benefits are excluded from the average total deduction calculation beginning in 2004.

[c]Real values are in constant 2014 dollars adjusted by changes in the CPI-U for all items.

[d]Real values are in constant 2014 dollars adjusted by changes in the CPI-U for food at home.

Table A.28. Comparison of number of SNAP participants by gender and age for fiscal years 1989 to 2014

Time period	Total participants (000)	Female participants (000)	Male participants (000)	Children (age 0 to 17) (000)	Non-elderly adults (age 18 to 59) (000)	Elderly individuals (age 60 or older) (000)
Fiscal year 1989	18,956	11,334	7,612	9,447	7,623	1,562
Fiscal year 1990	20,440	12,169	8,265	10,143	8,245	1,574
Fiscal year 1991	22,988	13,679	9,300	11,967	9,397	1,624
Fiscal year 1992	25,775	15,204	10,566	13,368	10,700	1,703
Fiscal year 1993	27,595	16,276	11,316	14,213	11,499	1,870
Fiscal year 1994	28,009	16,453	11,552	14,410	11,615	1,955
Fiscal year 1995	26,955	16,025	10,926	13,883	11,118	1,923
Fiscal year 1996	25,926	15,373	10,549	13,214	10,783	1,895
Fiscal year 1997	23,117	13,880	9,233	11,871	9,385	1,834
Fiscal year 1998	19,969	11,967	7,926	10,546	7,772	1,637
Fiscal year 1999	18,149	10,878	7,226	9,354	7,090	1,699
Fiscal year 2000	17,091	10,198	6,891	8,765	6,623	1,702
Fiscal year 2001	17,297	10,347	6,949	8,841	6,789	1,660
Fiscal year 2002	19,041	11,269	7,769	9,712	7,636	1,687
Fiscal year 2003	20,764	12,211	8,552	10,554	8,516	1,691
Fiscal year 2004	23,279	13,697	9,573	11,635	9,720	1,920
Fiscal year 2005	24,794	14,656	10,132	12,363	10,383	2,046
Fiscal year 2006	25,472	14,957	10,515	12,514	10,732	2,227
Fiscal year 2007	25,775	15,120	10,655	12,605	10,909	2,261
Fiscal year 2008	27,607	16,151	11,456	13,359	11,732	2,515
Fiscal year 2009	32,889	18,854	14,035	15,617	14,543	2,728
Fiscal year 2010	39,759	22,405	17,354	18,516	18,121	3,122
Fiscal year 2011	44,148	24,936	19,212	19,926	20,452	3,770
Fiscal year 2012	46,022	25,945	20,076	20,500	21,367	4,154
Fiscal year 2013	47,098	26,447	20,651	20,889	21,845	4,365
Fiscal year 2014	45,874	25,762	20,112	20,271	20,952	4,651

Source: Fiscal Years 1989 to 2014 Supplemental Nutrition Assistance Program Quality Control samples.

Notes: The fiscal year 2003 through fiscal year 2014 estimates differ methodologically from estimates for earlier years and, in some cases, from estimates presented in reports prior to 2009. Under the current methodology, the weighting of the SNAP QC data reflects adjustments to FNS' Program Operations counts of households to account for receipt of benefits in error or for disaster assistance. In addition, the weighted SNAP QC data match adjusted Program Operations counts of households, individuals, and benefit amounts. Beginning with the fiscal year 2009 report, we also incorporated corrected SNAP Program Operations data from Missouri for every fiscal year from 2003 to 2008. Additionally, beginning with the fiscal year 2014 report, we used revised versions of the fiscal year 2007 through fiscal year 2012 SNAP QC datafiles that better reflect State BBCE and vehicle rules and newly identify non-elderly individuals with a disability, similar to the fiscal year 2013 and 2014 SNAP QC files. As a result, totals for these years may vary slightly from those printed in the fiscal year reports.

The number of participants by gender and age do not sum to the total number of SNAP participants in certain years because some individuals have missing or unknown gender or age and are excluded from those columns.

APPENDIX B

DETAILED TABLES OF SNAP HOUSEHOLDS BY STATE

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Table B.1. Distribution of participating households, individuals, and benefits by State

State	SNAP households		Participants in households		Monthly SNAP benefits	
	Number (000)	Percent	Number (000)	Percent	Dollars (000)	Percent
Total[a]	22,445	100.0	45,874	100.0	5,689,647	100.0
Alabama	415	1.9	893	1.9	109,003	1.9
Alaska	37	0.2	87	0.2	14,431	0.3
Arizona	440	2.0	1,011	2.2	119,298	2.1
Arkansas	216	1.0	476	1.0	53,026	0.9
California	1,990	8.9	4,256	9.3	600,114	10.5
Colorado	230	1.0	497	1.1	62,331	1.1
Connecticut	239	1.1	428	0.9	55,854	1.0
Delaware	71	0.3	149	0.3	17,952	0.3
District of Columbia	79	0.4	140	0.3	17,590	0.3
Florida	1,921	8.6	3,526	7.7	451,839	7.9
Georgia	824	3.7	1,784	3.9	226,579	4.0
Guam	15	0.1	46	0.1	8,770	0.2
Hawaii	98	0.4	191	0.4	42,459	0.7
Idaho	89	0.4	208	0.5	23,974	0.4
Illinois	998	4.4	1,954	4.3	256,561	4.5
Indiana	398	1.8	877	1.9	105,816	1.9
Iowa	191	0.9	405	0.9	42,980	0.8
Kansas	133	0.6	293	0.6	32,700	0.6
Kentucky	389	1.7	803	1.8	93,609	1.6
Louisiana	395	1.8	874	1.9	106,467	1.9
Maine	122	0.5	229	0.5	26,103	0.5
Maryland	402	1.8	779	1.7	92,297	1.6
Massachusetts	483	2.2	853	1.9	102,062	1.8
Michigan	867	3.9	1,664	3.6	210,338	3.7
Minnesota	255	1.1	521	1.1	53,829	0.9
Mississippi	302	1.3	655	1.4	75,226	1.3
Missouri	402	1.8	853	1.9	101,418	1.8
Montana	57	0.3	121	0.3	14,312	0.3
Nebraska	76	0.3	172	0.4	19,530	0.3
Nevada	185	0.8	375	0.8	42,258	0.7
New Hampshire	53	0.2	108	0.2	11,308	0.2
New Jersey	437	1.9	874	1.9	106,906	1.9
New Mexico	191	0.8	426	0.9	49,970	0.9
New York	1,661	7.4	3,039	6.6	417,172	7.3
North Carolina	755	3.4	1,555	3.4	192,818	3.4
North Dakota	25	0.1	53	0.1	6,233	0.1
Ohio	843	3.8	1,732	3.8	207,927	3.7
Oklahoma	270	1.2	592	1.3	69,241	1.2
Oregon	444	2.0	782	1.7	91,866	1.6
Pennsylvania	886	3.9	1,782	3.9	208,957	3.7
Rhode Island	99	0.4	174	0.4	22,225	0.4
South Carolina	393	1.8	832	1.8	101,252	1.8
South Dakota	44	0.2	99	0.2	12,303	0.2
Tennessee	647	2.9	1,303	2.8	160,771	2.8
Texas	1,601	7.1	3,838	8.4	442,369	7.8
Utah	90	0.4	227	0.5	25,957	0.5
Vermont	48	0.2	92	0.2	10,651	0.2
Virgin Islands	12	0.1	28	0.1	4,504	0.1
Virginia	442	2.0	914	2.0	107,855	1.9
Washington	581	2.6	1,085	2.4	127,982	2.2
West Virginia	173	0.8	354	0.8	37,956	0.7
Wisconsin	417	1.9	831	1.8	90,741	1.6
Wyoming	15	0.1	35	0.1	3,955	0.1

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Due to rounding, the sum of individual categories may not match the table total.

Table B.2. Average values of selected characteristics by State

State	Average values						
	Gross countable income as a percentage of poverty guideline (percent)	Gross countable income (dollars)	Net countable income (dollars)[a]	Total deduction (dollars)[b]	SNAP benefit (dollars)	Household size (individuals)	Certification period (months)
Total	57.8	759	335	538	253	2.0	12.9
Alabama	51.9	692	341	442	262	2.1	14.9
Alaska	52.3	943	486	614	392	2.4	7.2
Arizona	54.8	783	389	482	271	2.3	10.1
Arkansas	52.4	727	422	366	246	2.2	17.6
California	44.5	622	211	610	302	2.1	12.4
Colorado	57.7	779	313	562	271	2.2	11.5
Connecticut	68.4	850	268	720	234	1.8	15.9
Delaware	60.2	811	366	545	254	2.1	13.8
District of Columbia	50.0	604	333	438	222	1.8	14.5
Florida	52.8	673	276	502	235	1.8	8.7
Georgia	50.0	673	316	450	275	2.2	7.5
Guam	54.5	934	474	588	582	3.1	12.0
Hawaii	55.4	852	468	459	435	2.0	11.6
Idaho	63.1	886	404	577	270	2.3	10.3
Illinois	50.7	641	266	471	257	2.0	12.4
Indiana	52.9	727	353	466	266	2.2	11.6
Iowa	65.2	870	481	467	225	2.1	7.3
Kansas	61.5	825	415	484	247	2.2	13.6
Kentucky	49.7	664	372	377	241	2.1	12.4
Louisiana	53.4	720	343	448	270	2.2	16.2
Maine	77.1	959	400	638	214	1.9	12.0
Maryland	63.2	811	369	539	230	1.9	8.6
Massachusetts	76.3	926	331	693	211	1.8	18.2
Michigan	62.3	795	300	701	243	1.9	15.3
Minnesota	66.0	872	495	471	211	2.0	12.9
Mississippi	50.0	679	381	363	249	2.2	18.7
Missouri	54.7	726	356	450	252	2.1	16.6
Montana	58.8	779	357	523	250	2.1	15.3
Nebraska	60.6	837	406	525	256	2.3	13.4
Nevada	59.8	790	431	431	228	2.0	7.7
New Hampshire	79.6	1,048	464	671	215	2.1	7.1
New Jersey	70.0	897	338	699	245	2.0	15.3
New Mexico	52.9	742	375	455	262	2.2	15.4
New York	73.4	884	279	765	251	1.8	20.7
North Carolina	53.4	691	343	453	255	2.1	8.3
North Dakota	72.4	944	373	664	252	2.1	7.8
Ohio	60.3	770	361	504	247	2.1	11.9
Oklahoma	52.3	702	380	414	256	2.2	15.2
Oregon	64.7	816	357	557	207	1.8	12.0
Pennsylvania	69.0	890	383	668	236	2.0	16.2
Rhode Island	69.2	842	279	742	224	1.8	16.0
South Carolina	48.9	651	330	393	257	2.1	8.1
South Dakota	61.4	840	328	625	282	2.3	13.8
Tennessee	48.6	631	322	381	248	2.0	11.9
Texas	56.2	826	417	489	276	2.4	11.9
Utah	55.8	839	427	506	290	2.5	7.3
Vermont	91.5	1,155	370	916	221	1.9	14.6
Virgin Islands	51.1	703	403	353	363	2.2	7.1
Virginia	53.1	718	366	430	244	2.1	13.3
Washington	62.3	805	353	617	220	1.9	15.2
West Virginia	59.5	772	451	398	219	2.0	14.0
Wisconsin	74.8	961	454	647	217	2.0	11.6
Wyoming	57.6	829	423	500	267	2.4	10.5

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Because net income is not used in their benefit determinations, 23,481 MFIP households and 565,481 SSI-CAP households in States that use standardized SSI-CAP benefits are excluded from this column.

[b] Because deductions are not used in their benefit determinations, 565,481 SSI-CAP households in States that use standardized SSI-CAP benefits are excluded from this column.

Table B.3. Distribution of participating households by poverty status and by State

State	Number (000)	Gross countable income as a percentage of the poverty guideline							
		Zero gross income		1% to 50%		51% to 100%		101% or more	
		Number (000)	Row percent	Number (000)	Row percent	Number (000)	Row percent	Number (000)	Row percent
Total[a]	22,445	4,919	21.9	4,755	21.2	9,088	40.5	3,684	16.4
Alabama	415	96	23.2	93	22.3	181	43.6	45	10.9
Alaska	37	9	24.1	9	25.7	13	36.0	5	14.2
Arizona	440	104	23.7	101	23.1	159	36.1	76	17.2
Arkansas	216	47	21.8	46	21.5	100	46.2	23	10.5
California	1,990	489	24.6	794	39.9	496	24.9	211	10.6
Colorado	230	39	16.8	56	24.4	102	44.3	33	14.5
Connecticut	239	43	18.2	45	19.0	90	37.9	59	24.9
Delaware	71	14	19.4	18	25.6	23	33.0	16	22.0
District of Columbia	79	27	33.8	17	21.0	25	31.1	11	14.2
Florida	1,921	575	30.0	298	15.5	771	40.2	276	14.4
Georgia	824	247	30.0	167	20.3	301	36.5	109	13.2
Guam	15	3	17.0	5	34.9	4	27.3	3	20.9
Hawaii	98	17	17.9	25	25.7	42	43.4	13	12.9
Idaho	89	13	14.4	17	19.1	44	49.5	15	17.0
Illinois	998	299	29.9	186	18.6	383	38.4	130	13.1
Indiana	398	90	22.6	89	22.3	168	42.3	51	12.8
Iowa	191	35	18.4	36	19.0	77	40.1	43	22.5
Kansas	133	24	18.4	20	15.3	68	51.2	20	15.1
Kentucky	389	101	25.8	83	21.3	167	42.8	39	10.1
Louisiana	395	77	19.5	93	23.5	183	46.2	42	10.7
Maine	122	16	13.4	14	11.4	58	47.5	34	27.7
Maryland	402	82	20.5	85	21.1	146	36.4	88	22.0
Massachusetts	483	61	12.6	77	15.9	217	44.8	129	26.7
Michigan	867	195	22.4	137	15.8	355	40.9	180	20.8
Minnesota	255	24	9.5	65	25.6	111	43.7	54	21.2
Mississippi	302	74	24.4	63	21.0	139	46.2	25	8.4
Missouri	402	91	22.7	77	19.2	184	45.8	49	12.3
Montana	57	13	22.3	10	17.9	24	42.0	10	17.7
Nebraska	76	12	16.4	15	19.9	36	47.2	13	16.5
Nevada	185	42	22.7	40	21.3	67	35.9	37	20.1
New Hampshire	53	5	9.7	6	12.1	26	48.9	15	29.4
New Jersey	437	41	9.4	99	22.6	198	45.4	99	22.6
New Mexico	191	38	20.1	48	25.1	83	43.8	21	11.0
New York	1,661	158	9.5	311	18.7	862	51.9	329	19.8
North Carolina	755	217	28.8	155	20.5	249	33.0	134	17.8
North Dakota	25	3	10.8	5	19.6	11	44.2	6	25.4
Ohio	843	156	18.4	156	18.5	398	47.2	134	15.9
Oklahoma	270	61	22.5	61	22.6	119	43.9	30	11.0
Oregon	444	102	23.0	77	17.2	157	35.5	108	24.3
Pennsylvania	886	145	16.3	141	16.0	391	44.2	209	23.5
Rhode Island	99	18	18.7	13	13.3	43	43.2	25	24.8
South Carolina	393	95	24.2	101	25.8	159	40.5	37	9.5
South Dakota	44	9	19.9	8	17.5	19	44.5	8	18.1
Tennessee	647	179	27.7	132	20.4	266	41.1	70	10.8
Texas	1,601	372	23.3	336	21.0	641	40.1	252	15.7
Utah	90	19	20.9	19	21.5	39	43.4	13	14.2
Vermont	48	3	6.5	6	12.3	19	39.4	20	41.7
Virgin Islands	12	2	13.7	5	40.7	3	26.2	2	19.4
Virginia	442	94	21.3	104	23.7	187	42.4	56	12.6
Washington	581	134	23.0	100	17.1	226	38.8	122	21.0
West Virginia	173	31	18.1	32	18.3	88	50.5	23	13.1
Wisconsin	417	74	17.8	56	13.4	161	38.5	127	30.3
Wyoming	15	3	20.6	3	19.4	7	45.4	2	14.5

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Due to rounding, the sum of individual categories may not match the table total.

Table B.4. Distribution of participating households by shelter-related characteristics and by State

State	Households with shelter deduction		Households at the shelter cap		Average monthly shelter expense (dollars)	Average monthly shelter expense among households with expense (dollars)	Average shelter deduction[a] (dollars)
	Number (000)	Percent	Number (000)	Percent			
Total[b]	16,159	72.0	4,474	19.9	610	748	393
Alabama	287	69.0	42	10.2	464	598	308
Alaska	23	63.7	3	8.5	568	697	405
Arizona	278	63.2	73	16.6	507	695	333
Arkansas	113	52.3	12	5.6	364	517	247
California	1,850	92.9	770	38.7	709	743	410
Colorado	179	77.7	53	23.2	655	792	404
Connecticut	196	82.1	88	36.9	925	1,120	569
Delaware	48	68.5	16	22.5	620	822	404
District of Columbia	62	78.3	5	6.9	454	493	303
Florida	1,308	68.1	344	17.9	543	761	391
Georgia	485	58.9	100	12.1	447	664	344
Guam	6	42.2	1	4.1	294	471	251
Hawaii	49	50.5	5	4.6	388	558	286
Idaho	72	80.9	17	19.2	638	722	361
Illinois	642	64.3	138	13.8	491	694	375
Indiana	265	66.5	51	12.8	498	664	343
Iowa	125	65.1	24	12.7	494	602	300
Kansas	96	72.2	14	10.6	517	603	306
Kentucky	223	57.4	21	5.5	375	525	270
Louisiana	258	65.3	37	9.3	455	595	301
Maine	100	81.6	26	21.4	837	957	496
Maryland	286	71.2	77	19.2	609	747	369
Massachusetts	414	85.8	122	25.2	882	997	521
Michigan	801	92.4	363	41.8	818	838	469
Minnesota	161	63.1	29	11.2	528	715	348
Mississippi	142	47.1	16	5.3	344	478	254
Missouri	252	62.8	33	8.2	442	599	311
Montana	40	69.7	10	17.2	568	722	385
Nebraska	57	75.3	14	18.3	602	703	360
Nevada	109	58.9	18	9.7	472	681	321
New Hampshire	45	86.4	13	24.7	880	930	461
New Jersey	422	96.6	121	27.8	871	874	463
New Mexico	114	59.8	24	12.8	457	597	325
New York	1,161	69.9	534	32.1	979	1,017	530
North Carolina	451	59.7	110	14.6	479	676	353
North Dakota	20	81.5	6	24.6	710	794	427
Ohio	583	69.2	124	14.7	566	723	396
Oklahoma	174	64.4	25	9.3	443	566	295
Oregon	330	74.3	87	19.6	646	814	407
Pennsylvania	816	92.1	311	35.1	837	848	450
Rhode Island	95	96.4	40	40.2	914	936	525
South Carolina	197	50.2	30	7.6	366	554	286
South Dakota	31	70.7	12	26.7	691	844	467
Tennessee	350	54.1	49	7.6	378	599	302
Texas	1,010	63.1	180	11.2	484	639	314
Utah	61	67.9	15	16.9	549	683	336
Vermont	47	98.3	19	38.8	1,194	1,199	619
Virgin Islands	6	45.1	1	5.2	275	397	203
Virginia	274	62.2	50	11.3	444	588	296
Washington	538	92.6	105	18.1	710	732	396
West Virginia	115	66.1	11	6.2	443	540	273
Wisconsin	381	91.4	84	20.2	781	808	412
Wyoming	10	67.5	2	16.4	509	638	313

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Over households with a shelter deduction.

[b] Due to rounding, the sum of individual categories may not match the table total.

Table B.5. Distribution of participating households by household composition and by State

State	Households with: Children		Elderly individuals		Non-elderly individuals with disabilities		Single adults with children		Adults age 18 to 49 without disabilities in childless households[a]	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total[b]	9,789	43.6	4,255	19.0	4,579	20.4	5,591	24.9	4,333	19.3
Alabama	195	46.9	63	15.3	111	26.6	132	31.8	82	19.7
Alaska	16	43.4	7	17.9	6	17.1	8	21.6	9	24.3
Arizona	222	50.4	65	14.9	73	16.6	115	26.2	86	19.5
Arkansas	100	46.4	31	14.5	57	26.4	61	28.3	43	19.7
California	1,146	57.6	180	9.0	48	2.4	519	26.1	510	25.6
Colorado	111	48.4	41	17.7	49	21.5	60	26.2	33	14.5
Connecticut	83	35.0	48	20.1	53	22.2	49	20.6	51	21.6
Delaware	34	48.0	9	12.8	10	14.6	21	30.4	14	19.7
District of Columbia	26	33.2	13	16.4	15	19.4	19	24.0	22	27.5
Florida	670	34.9	443	23.1	328	17.1	325	16.9	465	24.2
Georgia	385	46.6	137	16.6	140	17.0	249	30.2	180	21.8
Guam	10	68.1	2	15.3	0	2.9	3	20.3	2	10.8
Hawaii	35	36.4	22	23.0	15	15.6	17	17.6	20	20.9
Idaho	46	52.2	15	17.1	20	23.1	22	24.2	11	12.7
Illinois	391	39.2	188	18.8	168	16.8	237	23.8	256	25.7
Indiana	193	48.6	53	13.4	102	25.7	122	30.6	73	18.3
Iowa	84	44.0	28	14.5	39	20.2	55	28.8	42	22.1
Kansas	61	46.0	22	16.5	39	29.4	36	27.2	15	11.6
Kentucky	161	41.3	62	15.9	116	29.8	93	24.0	89	23.0
Louisiana	197	49.8	63	16.1	100	25.2	150	38.0	68	17.3
Maine	42	34.4	29	23.9	40	32.6	23	18.9	18	15.1
Maryland	165	41.1	71	17.7	79	19.6	110	27.4	86	21.5
Massachusetts	161	33.3	130	27.0	138	28.5	108	22.4	75	15.6
Michigan	309	35.6	145	16.7	225	26.0	183	21.1	201	23.2
Minnesota	104	40.6	47	18.3	64	24.9	57	22.2	39	15.4
Mississippi	139	46.1	53	17.7	69	23.0	88	29.2	62	20.6
Missouri	167	41.6	73	18.1	107	26.7	101	25.2	74	18.4
Montana	24	41.3	10	17.9	13	22.4	13	23.4	11	20.0
Nebraska	37	48.1	12	15.9	20	26.0	23	30.0	10	12.8
Nevada	74	40.0	34	18.3	34	18.5	38	20.6	41	22.4
New Hampshire	24	45.8	10	19.2	19	36.3	16	30.3	5	9.3
New Jersey	201	46.1	115	26.2	82	18.8	106	24.2	50	11.5
New Mexico	93	48.9	27	14.2	39	20.3	51	26.8	35	18.1
New York	568	34.2	546	32.9	392	23.6	307	18.5	208	12.5
North Carolina	339	44.8	142	18.8	133	17.6	208	27.5	165	21.8
North Dakota	12	47.3	4	17.7	7	26.8	8	33.2	3	12.9
Ohio	359	42.6	155	18.4	243	28.9	236	28.0	122	14.5
Oklahoma	124	46.0	41	15.1	72	26.6	78	28.8	44	16.4
Oregon	140	31.7	92	20.8	86	19.4	70	15.9	111	25.0
Pennsylvania	353	39.8	182	20.5	265	29.9	221	24.9	150	17.0
Rhode Island	34	34.2	23	23.7	26	26.8	21	20.8	19	19.2
South Carolina	185	47.0	71	18.2	77	19.5	134	34.1	68	17.2
South Dakota	21	48.6	7	16.8	10	23.5	13	30.3	6	14.7
Tennessee	270	41.7	120	18.5	138	21.3	164	25.4	150	23.2
Texas	947	59.2	313	19.5	303	18.9	510	31.9	117	7.3
Utah	49	55.2	12	13.4	18	20.2	26	28.6	12	13.5
Vermont	17	35.6	14	28.6	14	28.9	10	20.3	6	12.4
Virgin Islands	7	52.9	2	18.6	0	3.3	4	35.0	2	17.5
Virginia	205	46.4	62	14.0	101	22.8	128	29.0	87	19.7
Washington	207	35.6	104	17.8	123	21.1	99	17.1	158	27.2
West Virginia	69	39.9	34	19.6	57	32.9	38	21.8	32	18.4
Wisconsin	169	40.4	78	18.8	92	22.1	96	23.1	90	21.5
Wyoming	8	55.7	2	15.0	3	19.7	6	38.0	1	9.3

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] With some exceptions, these participants are subject to work requirements and a time limit.

[b] Due to rounding, the sum of individual categories may not match the table total.

Table B.6. Distribution of participating households by selected countable income sources and by State

State	Households with countable:									
	TANF[a]		GA		SSI		Social Security		Earned income	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total[b]	1,362	6.1	694	3.1	4,568	20.4	5,505	24.5	7,016	31.3
Alabama	11	2.6	–	–	102	24.6	116	27.9	112	27.0
Alaska	4	11.6	11	29.0	6	16.1	9	23.5	11	28.9
Arizona	14	3.2	–	–	69	15.6	89	20.2	176	39.9
Arkansas	4	1.8	0	0.2	53	24.8	59	27.4	62	28.7
California	461	23.2	113	5.7	–	–	158	8.0	759	38.1
Colorado	–	–	40	17.2	47	20.3	53	22.9	78	34.1
Connecticut	14	5.7	16	6.8	49	20.5	63	26.3	70	29.4
Delaware	4	5.3	7	9.2	9	12.2	12	17.5	25	35.7
District of Columbia	15	19.0	1	1.1	15	19.0	15	18.9	14	17.3
Florida	60	3.1	4	0.2	388	20.2	489	25.5	512	26.6
Georgia	12	1.5	1	0.1	137	16.6	193	23.4	251	30.5
Guam	2	13.9	0	3.2	–	–	2	14.3	7	44.7
Hawaii	7	6.9	6	5.7	19	19.3	23	23.2	33	34.2
Idaho	3	3.3	8	9.6	19	21.0	24	27.3	37	42.0
Illinois	45	4.5	18	1.8	180	18.0	218	21.8	284	28.4
Indiana	10	2.5	–	–	89	22.3	96	24.2	137	34.3
Iowa	12	6.5	1	0.3	32	16.9	47	24.5	80	41.8
Kansas	6	4.3	0	0.3	32	24.1	38	28.9	46	34.8
Kentucky	21	5.3	1	0.2	103	26.5	100	25.6	96	24.6
Louisiana	3	0.8	1	0.4	109	27.7	97	24.5	119	30.2
Maine	7	5.7	30	24.3	28	23.3	53	43.6	35	28.5
Maryland	20	4.9	18	4.4	73	18.2	99	24.6	117	29.2
Massachusetts	37	7.6	19	4.0	148	30.7	180	37.3	104	21.4
Michigan	32	3.7	3	0.4	191	22.1	239	27.5	290	33.5
Minnesota	20	7.7	19	7.4	63	24.8	69	26.9	91	35.6
Mississippi	10	3.4	–	–	75	24.9	81	26.9	74	24.4
Missouri	32	7.9	1	0.2	98	24.4	118	29.4	98	24.3
Montana	2	4.2	0	0.4	11	20.0	16	27.6	18	31.5
Nebraska	6	7.5	5	6.0	16	21.1	22	29.3	28	36.2
Nevada	13	6.8	0	0.1	31	16.8	44	23.9	62	33.3
New Hampshire	3	4.9	8	14.4	14	26.7	20	37.9	17	32.2
New Jersey	28	6.4	29	6.6	101	23.1	132	30.3	142	32.5
New Mexico	17	8.7	4	2.0	41	21.7	41	21.4	64	33.6
New York	74	4.5	187	11.3	588	35.4	496	29.8	462	27.8
North Carolina	10	1.3	6	0.7	129	17.1	187	24.8	221	29.3
North Dakota	1	3.9	–	–	5	21.2	8	31.7	10	41.0
Ohio	49	5.8	16	1.9	223	26.5	244	28.9	248	29.4
Oklahoma	6	2.3	65	23.9	61	22.7	76	28.2	74	27.3
Oregon	30	6.7	0	0.1	77	17.3	113	25.4	150	33.7
Pennsylvania	62	7.0	1	0.1	254	28.7	279	31.5	246	27.8
Rhode Island	5	5.5	0	0.3	27	27.5	32	32.5	26	26.7
South Carolina	17	4.3	–	–	74	18.8	95	24.0	124	31.4
South Dakota	2	5.5	0	0.5	10	23.0	12	26.8	16	36.1
Tennessee	39	6.1	–	–	122	18.9	176	27.3	159	24.6
Texas	39	2.4	–	–	277	17.3	327	20.4	654	40.8
Utah	4	4.0	1	0.9	17	18.8	19	21.5	34	37.7
Vermont	5	9.5	1	2.7	11	22.4	21	44.3	15	31.6
Virgin Islands	1	4.2	0	3.6	0	0.4	2	19.0	5	42.4
Virginia	30	6.7	1	0.2	92	20.8	106	23.9	150	34.1
Washington	30	5.2	46	8.0	122	21.0	120	20.7	169	29.1
West Virginia	5	2.7	6	3.3	54	31.4	51	29.2	41	23.6
Wisconsin	21	5.1	1	0.2	72	17.2	124	29.6	160	38.4
Wyoming	0	0.8	0	0.9	3	18.6	3	19.4	5	36.7

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] This does not include households receiving a noncash benefit or a noncountable cash benefit (e.g., households participating in MFIP).

[b] Due to rounding, the sum of individual categories may not match the table total.

– No sample data in this category.

Table B.7. Average values of selected countable income sources by State

State	Average countable values (dollars)[a]				
	TANF[b]	GA	SSI	Social Security	Earned income
Total	383	225	589	820	1,064
Alabama	231	–	536	759	1,026
Alaska	641	360	516	796	1,273
Arizona	223	–	591	803	1,133
Arkansas	154	220	555	764	1,058
California	471	244	–	843	899
Colorado	–	295	567	798	1,065
Connecticut	507	189	600	886	1,191
Delaware	299	106	635	893	1,263
District of Columbia	317	270	651	826	1,178
Florida	262	210	558	763	1,120
Georgia	206	225	540	842	1,023
Guam	219	108	–	848	1,559
Hawaii	525	324	580	847	1,256
Idaho	107	46	537	795	1,152
Illinois	334	134	577	848	952
Indiana	200	–	577	772	957
Iowa	349	557	509	850	1,063
Kansas	283	274	546	800	1,112
Kentucky	245	601	597	758	964
Louisiana	392	384	574	695	1,005
Maine	428	11	542	909	1,163
Maryland	555	187	599	881	1,190
Massachusetts	450	293	667	916	1,161
Michigan	280	160	647	896	999
Minnesota[c]	1	171	615	771	1,164
Mississippi	144	–	533	697	1,112
Missouri	239	520	570	789	1,080
Montana	445	278	564	798	1,149
Nebraska	326	62	518	785	1,045
Nevada	360	189	570	913	1,085
New Hampshire	496	142	580	890	1,320
New Jersey	351	168	528	846	1,183
New Mexico	333	245	564	709	1,064
New York	580	354	613	783	1,065
North Carolina	220	315	546	867	1,076
North Dakota	284	–	482	827	1,161
Ohio	359	167	578	817	971
Oklahoma	213	37	556	754	994
Oregon	436	432	573	921	1,152
Pennsylvania	343	205	643	856	1,121
Rhode Island	422	251	584	866	1,137
South Carolina	225	–	584	770	908
South Dakota	406	371	528	783	1,142
Tennessee	179	–	530	806	979
Texas	230	–	618	793	1,161
Utah	405	287	567	763	1,249
Vermont	510	261	629	1,010	1,316
Virgin Islands	349	177	290	763	1,057
Virginia	276	130	573	757	983
Washington	393	107	638	850	1,284
West Virginia	304	304	612	807	1,062
Wisconsin	542	218	659	979	1,109
Wyoming	395	444	574	735	1,247

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Average values are over households with income source.

[b] This does not include households receiving a noncash benefit or a noncountable cash benefit (e.g., households participating in MFIP).

[c] TANF income is not included in MFIP gross income or used in the MFIP benefit calculation. Because of federal Quality Control System constraints, this means that only a placeholder TANF amount, typically $1, may be reported for MFIP households in the SNAP Quality Control datafile.

– No sample data in this category.

Table B.8. Distribution of participating households by earnings-related characteristics and by State

State	Households with earnings			Average earned income deduction (dollars)	
	Number (000)	Percent	Average earnings (dollars)	All households[a]	Households with deduction
Total[b]	7,016	31.3	1,064	69	213
Alabama	112	27.0	1,026	55	205
Alaska	11	28.9	1,273	73	254
Arizona	176	39.9	1,133	90	226
Arkansas	62	28.7	1,058	61	211
California	759	38.1	899	68	180
Colorado	78	34.1	1,065	72	213
Connecticut	70	29.4	1,191	70	238
Delaware	25	35.7	1,263	90	252
District of Columbia	14	17.3	1,178	41	235
Florida	512	26.6	1,120	62	224
Georgia	251	30.5	1,023	62	204
Guam	7	44.7	1,559	139	312
Hawaii	33	34.2	1,256	86	251
Idaho	37	42.0	1,152	97	230
Illinois	284	28.4	952	54	190
Indiana	137	34.3	957	66	191
Iowa	80	41.8	1,063	89	212
Kansas	46	34.8	1,112	77	222
Kentucky	96	24.6	964	48	193
Louisiana	119	30.2	1,005	62	201
Maine	35	28.5	1,163	66	232
Maryland	117	29.2	1,190	71	238
Massachusetts	104	21.4	1,161	51	232
Michigan	290	33.5	999	68	199
Minnesota	91	35.6	1,164	86	275
Mississippi	74	24.4	1,112	59	222
Missouri	98	24.3	1,080	52	216
Montana	18	31.5	1,149	72	232
Nebraska	28	36.2	1,045	76	209
Nevada	62	33.3	1,085	72	217
New Hampshire	17	32.2	1,320	85	264
New Jersey	142	32.5	1,183	77	236
New Mexico	64	33.6	1,064	74	213
New York	462	27.8	1,065	79	216
North Carolina	221	29.3	1,076	64	215
North Dakota	10	41.0	1,161	95	232
Ohio	248	29.4	971	57	194
Oklahoma	74	27.3	994	54	199
Oregon	150	33.7	1,152	78	231
Pennsylvania	246	27.8	1,121	64	224
Rhode Island	26	26.7	1,137	61	227
South Carolina	124	31.4	908	61	182
South Dakota	16	36.1	1,142	85	229
Tennessee	159	24.6	979	48	196
Texas	654	40.8	1,161	95	232
Utah	34	37.7	1,249	94	250
Vermont	15	31.6	1,316	83	263
Virgin Islands	5	42.4	1,057	90	211
Virginia	150	34.1	983	67	197
Washington	169	29.1	1,284	87	257
West Virginia	41	23.6	1,062	50	212
Wisconsin	160	38.4	1,109	85	223
Wyoming	5	36.7	1,247	91	249

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Because the earnings deduction is not used in their benefit determinations, 720,552 SSI-CAP households are excluded from this column.

[b] Due to rounding, the sum of individual categories may not match the table total.

Table B.9. Distribution of entrant households with and without expedited service by State

State	Total entrant households (000)	Entrant households eligible for and receiving expedited service		Entrant households eligible for but not receiving expedited service		Entrant households not eligible for expedited service	
		Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total[a]	872	429	49.2	56	6.5	386	44.3
Alabama	17	8	47.7	2	9.4	7	43.0
Alaska	2	1	34.0	0	7.4	1	58.6
Arizona	22	10	44.3	0	2.1	12	53.5
Arkansas	12	3	21.8	1	7.0	9	71.2
California	76	49	63.5	5	6.2	23	30.3
Colorado	15	10	64.8	1	5.7	4	29.5
Connecticut	7	4	56.3	0	6.5	3	37.1
Delaware	2	1	57.8	0	7.0	1	35.2
District of Columbia	4	2	65.0	–	–	1	35.0
Florida	73	33	45.6	2	3.0	37	51.4
Georgia	43	13	30.7	9	21.0	21	48.3
Guam	0	0	37.7	0	14.2	0	48.1
Hawaii	4	2	42.5	0	6.0	2	51.4
Idaho	5	2	41.6	–	–	3	58.4
Illinois	19	12	66.0	1	6.0	5	28.0
Indiana	16	7	43.1	2	10.3	7	46.6
Iowa	8	2	31.1	0	4.9	5	64.0
Kansas	5	2	45.9	0	4.5	2	49.6
Kentucky	19	10	51.9	0	2.0	9	46.1
Louisiana	20	5	26.4	2	12.2	12	61.3
Maine	2	1	44.7	0	6.9	1	48.3
Maryland	21	13	59.2	2	9.2	7	31.6
Massachusetts	11	4	38.9	0	4.1	7	57.0
Michigan	23	13	55.1	2	9.2	8	35.7
Minnesota	8	4	49.3	0	3.4	4	47.3
Mississippi	8	5	59.6	–	–	3	40.4
Missouri	14	5	36.4	2	12.4	7	51.2
Montana	3	1	51.2	0	7.0	1	41.8
Nebraska	3	1	47.8	0	8.8	1	43.4
Nevada	9	5	57.1	–	–	4	42.9
New Hampshire	2	1	59.2	0	7.3	1	33.5
New Jersey	7	2	26.3	1	7.7	4	66.0
New Mexico	11	5	46.9	1	9.8	5	43.3
New York	56	43	76.7	–	–	13	23.3
North Carolina	30	15	51.1	3	9.2	12	39.8
North Dakota	2	1	53.6	–	–	1	46.4
Ohio	27	10	36.8	3	11.6	14	51.7
Oklahoma	50	19	37.9	2	3.6	29	58.5
Oregon	17	8	46.9	1	8.1	8	44.9
Pennsylvania	30	21	71.7	1	2.9	8	25.5
Rhode Island	3	2	70.1	0	10.1	1	19.8
South Carolina	16	6	38.1	1	6.8	9	55.1
South Dakota	2	1	53.4	0	6.9	1	39.7
Tennessee	16	8	49.7	1	4.2	7	46.2
Texas	68	24	35.6	7	9.5	37	54.9
Utah	4	2	39.7	0	2.6	2	57.6
Vermont	2	0	10.2	0	14.1	2	75.8
Virgin Islands	1	0	39.4	–	–	0	60.6
Virginia	11	4	34.3	0	4.3	7	61.5
Washington	21	12	57.0	1	5.5	8	37.5
West Virginia	6	3	54.7	–	–	3	45.3
Wisconsin	19	12	62.4	–	–	7	37.6
Wyoming	1	1	71.0	0	5.9	0	23.1

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Due to rounding, the sum of individual categories may not match the table total.

– No sample data in this category.

Table B.10. Distribution of participating households by race/Hispanic status of household head and by State

State	Race/Hispanic status[a] of household head									
	White, not Hispanic		African American, not Hispanic		Hispanic, any race		Other, not Hispanic[b]		Missing/unknown[c]	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total[d]	8,940	39.8	5,717	25.5	2,448	10.9	938	4.2	4,403	19.6
Alabama	178	42.8	219	52.6	5	1.1	1	0.2	13	3.2
Alaska	14	39.0	2	5.2	0	0.5	18	48.1	3	7.2
Arizona	188	42.6	37	8.5	121	27.4	51	11.7	43	9.8
Arkansas	123	56.9	76	35.3	3	1.3	3	1.2	11	5.2
California	464	23.3	285	14.3	665	33.4	122	6.1	454	22.8
Colorado	50	21.8	9	4.1	30	13.0	6	2.8	134	58.3
Connecticut	101	42.1	53	22.3	69	29.1	4	1.8	11	4.6
Delaware	7	9.2	5	6.8	0	0.2	0	0.6	59	83.1
District of Columbia	1	1.5	71	90.0	2	2.4	0	0.5	4	5.6
Florida	682	35.5	518	27.0	537	28.0	23	1.2	161	8.4
Georgia	261	31.7	486	58.9	21	2.5	13	1.6	44	5.3
Guam	0	1.9	–	–	–	–	11	76.0	3	22.1
Hawaii	19	19.6	1	1.2	2	2.1	54	55.3	21	21.9
Idaho	71	80.4	1	1.1	6	7.3	3	3.3	7	8.0
Illinois	320	32.1	216	21.7	32	3.2	19	1.9	410	41.1
Indiana	268	67.2	92	23.1	11	2.9	6	1.6	21	5.2
Iowa	96	50.4	19	9.8	4	2.0	4	2.1	68	35.7
Kansas	63	47.2	21	15.7	6	4.3	3	2.2	40	30.5
Kentucky	312	80.3	59	15.2	4	1.0	3	0.8	11	2.7
Louisiana	118	29.9	244	61.9	4	1.1	5	1.3	23	5.7
Maine	114	93.6	3	2.2	1	0.6	3	2.3	2	1.3
Maryland	133	33.1	231	57.6	11	2.7	12	3.1	14	3.5
Massachusetts	256	53.0	66	13.7	107	22.2	28	5.8	26	5.4
Michigan	417	48.1	283	32.7	13	1.5	12	1.4	142	16.3
Minnesota	143	56.1	57	22.5	4	1.4	27	10.4	24	9.6
Mississippi	75	24.9	173	57.3	1	0.4	3	1.1	49	16.3
Missouri	251	62.6	95	23.8	1	0.4	5	1.3	48	12.0
Montana	39	68.1	0	0.4	0	0.5	12	20.3	6	10.7
Nebraska	50	65.8	14	17.9	4	4.7	4	4.9	5	6.6
Nevada	81	43.5	43	23.4	33	17.8	13	7.0	15	8.2
New Hampshire	48	90.7	1	2.6	2	3.2	1	1.7	1	1.7
New Jersey	154	35.2	124	28.4	90	20.6	22	5.1	47	10.7
New Mexico	26	13.5	3	1.5	68	35.5	17	8.9	77	40.6
New York	586	35.3	480	28.9	324	19.5	156	9.4	114	6.9
North Carolina	323	42.8	350	46.4	12	1.7	24	3.1	46	6.1
North Dakota	17	70.1	1	5.1	0	0.2	6	22.8	0	1.8
Ohio	544	64.6	258	30.7	3	0.4	12	1.4	25	3.0
Oklahoma	148	54.7	38	14.0	7	2.5	25	9.3	53	19.5
Oregon	335	75.6	23	5.2	5	1.1	27	6.0	54	12.2
Pennsylvania	500	56.4	277	31.3	10	1.1	84	9.4	15	1.7
Rhode Island	48	48.9	11	11.5	18	18.1	2	2.4	19	19.1
South Carolina	163	41.5	210	53.5	3	0.9	2	0.5	14	3.6
South Dakota	23	52.7	2	4.1	0	0.7	17	38.3	2	4.1
Tennessee	121	18.7	69	10.7	1	0.1	2	0.3	454	70.2
Texas	177	11.1	134	8.4	177	11.1	19	1.2	1,094	68.3
Utah	65	72.8	3	3.4	3	3.6	6	7.0	12	13.2
Vermont	26	53.8	0	0.9	0	0.3	1	1.8	21	43.2
Virgin Islands	0	3.3	9	71.7	2	18.5	–	–	1	6.4
Virginia	189	42.8	205	46.3	9	2.0	8	1.8	31	7.1
Washington	125	21.6	19	3.3	13	2.2	22	3.8	402	69.1
West Virginia	161	93.0	9	5.0	0	0.1	1	0.4	3	1.5
Wisconsin	248	59.6	109	26.2	2	0.4	15	3.6	43	10.3
Wyoming	12	78.8	0	1.3	1	5.3	1	5.4	1	9.2

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Codes to allow reporting of multiple races were implemented beginning in April 2007. We have grouped the codes together to form general race and ethnicity categories. Reporting of race and ethnicity is now voluntary and was missing for 16 percent of participants in fiscal year 2014. As a result, fiscal year 2014 race and ethnicity distributions are not comparable to distributions for years prior to fiscal year 2007.

[b] Other includes household heads that are Asian, Native American, or who reported multiple races that do not fit into previous categories.

[c] Missing/unknown includes household heads for which racial/ethnic information was not recorded on the application, is not available because the application was not found, or is unknown, and households with no household head and no adult listed on the file.

[d] Due to rounding, the sum of individual categories may not match the table total.

– No sample data in this category.

Table B.11. Distribution of participating households by use of standard utility allowance and by State

State	Number (000)	Standard utility allowance (SUA)-usage and entitlement[a]					
		Households with heating/cooling SUA		Households with another SUA		Households with no SUA	
		Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total[b]	22,445	15,093	67.2	1,484	6.6	5,280	23.5
Alabama	415	283	68.1	10	2.5	122	29.4
Alaska	37	14	37.1	14	38.9	9	24.0
Arizona	440	261	59.3	30	6.8	149	33.9
Arkansas	216	118	54.5	7	3.4	91	42.1
California	1,990	1,862	93.5	19	1.0	109	5.5
Colorado	230	148	64.4	28	12.1	54	23.5
Connecticut	239	196	82.3	0	0.2	42	17.5
Delaware	71	44	62.1	5	6.5	22	31.4
District of Columbia	79	70	88.5	1	1.5	8	10.0
Florida	1,921	1,063	55.4	102	5.3	755	39.3
Georgia	824	474	57.6	31	3.8	319	38.6
Guam	15	–	–	7	48.6	8	51.4
Hawaii	98	1	0.7	47	47.8	50	51.5
Idaho	89	63	70.8	12	13.4	14	15.8
Illinois	998	516	51.7	107	10.7	375	37.6
Indiana	398	239	60.1	12	3.0	147	36.9
Iowa	191	119	62.2	28	14.5	44	23.2
Kansas	133	90	67.7	15	11.3	28	21.0
Kentucky	389	228	58.5	26	6.8	132	34.0
Louisiana	395	249	63.0	23	5.9	112	28.3
Maine	122	91	74.2	13	10.9	18	14.9
Maryland	402	192	47.7	85	21.1	116	29.0
Massachusetts	483	377	78.1	40	8.3	66	13.7
Michigan	867	806	93.0	16	1.9	25	2.9
Minnesota	255	127	49.8	39	15.3	66	25.7
Mississippi	302	170	56.5	4	1.4	101	33.4
Missouri	402	248	61.9	23	5.7	130	32.4
Montana	57	36	63.4	3	4.9	18	31.7
Nebraska	76	52	68.3	6	7.5	18	24.2
Nevada	185	101	54.4	6	3.0	79	42.6
New Hampshire	53	36	68.6	11	20.5	6	10.9
New Jersey	437	426	97.7	6	1.4	4	0.9
New Mexico	191	108	56.7	15	7.8	60	31.5
New York	1,661	1,041	62.7	178	10.7	28	1.7
North Carolina	755	463	61.3	25	3.3	251	33.2
North Dakota	25	18	72.8	2	9.9	4	17.3
Ohio	843	538	63.8	36	4.3	269	31.9
Oklahoma	270	169	62.5	29	10.9	72	26.7
Oregon	444	315	71.0	23	5.2	106	23.8
Pennsylvania	886	832	93.9	12	1.3	12	1.4
Rhode Island	99	96	97.0	–	–	3	3.0
South Carolina	393	205	52.1	1	0.2	162	41.2
South Dakota	44	29	66.0	2	5.3	11	25.0
Tennessee	647	324	50.0	24	3.7	300	46.3
Texas	1,601	964	60.2	183	11.4	454	28.4
Utah	90	52	57.7	12	13.6	26	28.6
Vermont	48	48	99.2	0	0.1	0	0.7
Virgin Islands	12	–	–	0	3.2	12	96.8
Virginia	442	202	45.8	56	12.7	182	41.1
Washington	581	473	81.4	85	14.6	23	4.0
West Virginia	173	120	69.3	10	5.7	43	25.0
Wisconsin	417	387	92.7	11	2.7	19	4.6
Wyoming	15	9	60.0	1	6.8	5	33.2

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Because this deduction is not used in their benefit determinations, 23,481 MFIP households and 565,481 SSI-CAP households in States that use standardized SSI-CAP benefits are excluded from this category.

[b] Due to rounding, the sum of individual categories may not match the table total.

– No sample data in this category.

Table B.12. Distribution of participating categorically eligible households by public assistance status and by State

State	Total households (000)	Categorically eligible households					
		Total households		Pure public assistance households[a]		Other categorically eligible households[b]	
		Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total[c]	22,445	20,538	91.5	4,991	22.2	15,547	69.3
Alabama	415	415	100.0	78	18.7	338	81.3
Alaska	37	12	33.2	12	31.3	1	1.9
Arizona	440	440	100.0	58	13.2	382	86.8
Arkansas	216	41	18.9	38	17.8	2	1.1
California	1,990	1,990	100.0	537	27.0	1,453	73.0
Colorado	230	230	100.0	56	24.3	174	75.7
Connecticut	239	238	99.8	57	23.9	181	75.9
Delaware	71	71	100.0	15	21.5	56	78.5
District of Columbia	79	79	100.0	23	29.5	56	70.5
Florida	1,921	1,921	100.0	350	18.2	1,570	81.8
Georgia	824	824	100.0	114	13.9	710	86.1
Guam	15	15	100.0	2	16.2	13	83.8
Hawaii	98	98	100.0	28	28.9	69	71.1
Idaho	89	89	100.0	14	15.7	75	84.3
Illinois	998	998	100.0	180	18.0	818	82.0
Indiana	398	73	18.3	72	18.1	1	0.3
Iowa	191	191	100.0	36	18.5	156	81.5
Kansas	133	31	23.6	29	22.1	2	1.5
Kentucky	389	389	100.0	82	21.0	307	79.0
Louisiana	395	390	98.7	75	19.0	315	79.7
Maine	122	122	100.0	31	25.1	92	74.9
Maryland	402	401	99.9	91	22.6	310	77.3
Massachusetts	483	483	100.0	172	35.5	312	64.5
Michigan	867	867	100.0	163	18.8	704	81.2
Minnesota	255	255	100.0	97	38.2	158	61.8
Mississippi	302	302	100.0	59	19.7	242	80.3
Missouri	402	120	29.9	103	25.7	17	4.1
Montana	57	57	100.0	10	17.9	47	82.1
Nebraska	76	76	100.0	17	22.6	59	77.4
Nevada	185	185	100.0	34	18.3	151	81.7
New Hampshire	53	36	68.2	14	26.2	22	42.0
New Jersey	437	435	99.6	126	28.9	309	70.7
New Mexico	191	191	100.0	50	26.1	141	73.9
New York	1,661	1,661	100.0	672	40.5	989	59.5
North Carolina	755	755	100.0	94	12.5	661	87.5
North Dakota	25	25	100.0	5	19.6	20	80.4
Ohio	843	843	100.0	226	26.8	617	73.2
Oklahoma	270	270	100.0	55	20.2	216	79.8
Oregon	444	444	100.0	92	20.7	352	79.3
Pennsylvania	886	886	100.0	233	26.3	653	73.7
Rhode Island	99	99	100.0	26	26.1	73	73.9
South Carolina	393	393	100.0	65	16.4	329	83.6
South Dakota	44	13	29.1	10	22.4	3	6.7
Tennessee	647	132	20.4	118	18.3	14	2.1
Texas	1,601	1,601	100.0	201	12.6	1,400	87.4
Utah	90	21	23.3	17	18.6	4	4.7
Vermont	48	48	100.0	13	27.2	35	72.8
Virgin Islands	12	12	100.0	1	6.7	12	93.3
Virginia	442	94	21.2	87	19.7	7	1.5
Washington	581	581	100.0	145	25.0	436	75.0
West Virginia	173	173	100.0	43	24.9	130	75.1
Wisconsin	417	417	100.0	63	15.0	354	85.0
Wyoming	15	2	16.5	2	16.2	0	0.3

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Pure PA households are those in which each member (1) received SSI, (2) was covered by a cash TANF benefit, or (3) received GA income.

[b] These households are identified as categorically eligible in the SNAP Quality Control data but are not pure cash PA households. Most are likely eligible through broad-based categorical eligibility or because of the receipt of noncash TANF benefits or services such as child care or transportation subsidies. Most of these households meet the federal SNAP eligibility criteria.

[c] Due to rounding, the sum of individual categories may not match the table total.

Table B.13. Distribution of participating households by poverty status and by State, and effect of SNAP benefits on the poverty status of SNAP households

State	Total house-holds (000)	Distribution of households in relation to poverty guideline[a]								
		Based on cash only			Based on cash and SNAP benefits			Difference in percentage points		
		50 percent or less	51 to 100 percent	101 percent or more	50 percent or less	51 to 100 percent	101 percent or more	50 percent or less	51 to 100 percent	101 percent or more
Total[b]	22,445	43.1	40.5	16.4	29.9	43.7	26.3	-13.2	3.2	9.9
Alabama	415	45.5	43.6	10.9	31.5	50.6	18.0	-14.0	7.0	7.0
Alaska	37	49.8	36.0	14.2	31.8	41.7	26.5	-17.9	5.7	12.2
Arizona	440	46.7	36.1	17.2	35.8	38.9	25.3	-10.9	2.8	8.1
Arkansas	216	43.3	46.2	10.5	31.7	51.2	17.1	-11.6	5.1	6.6
California	1,990	64.5	24.9	10.6	36.1	46.4	17.5	-28.3	21.4	6.9
Colorado	230	41.2	44.3	14.5	26.1	48.8	25.2	-15.1	4.5	10.6
Connecticut	239	37.2	37.9	24.9	26.4	36.9	36.8	-10.9	-1.0	11.9
Delaware	71	45.0	33.0	22.0	34.5	35.7	29.9	-10.5	2.6	7.9
District of Columbia	79	54.8	31.1	14.2	41.2	40.7	18.1	-13.5	9.6	3.9
Florida	1,921	45.5	40.2	14.4	35.7	41.3	23.0	-9.7	1.1	8.6
Georgia	824	50.2	36.5	13.2	38.5	40.5	20.9	-11.7	4.0	7.7
Guam	15	51.9	27.3	20.9	24.5	34.6	40.9	-27.3	7.3	20.1
Hawaii	98	43.7	43.4	12.9	21.9	50.6	27.5	-21.8	7.2	14.6
Idaho	89	33.5	49.5	17.0	22.3	49.0	28.6	-11.2	-0.5	11.7
Illinois	998	48.5	38.4	13.1	36.1	43.9	20.0	-12.4	5.5	7.0
Indiana	398	44.9	42.3	12.8	32.4	46.4	21.2	-12.5	4.1	8.4
Iowa	191	37.4	40.1	22.5	25.9	44.7	29.5	-11.5	4.6	6.9
Kansas	133	33.7	51.2	15.1	23.7	51.5	24.9	-10.1	0.3	9.8
Kentucky	389	47.1	42.8	10.1	35.8	49.7	14.5	-11.3	6.9	4.5
Louisiana	395	43.1	46.2	10.7	29.7	52.3	18.0	-13.4	6.1	7.3
Maine	122	24.8	47.5	27.7	16.5	40.7	42.8	-8.3	-6.8	15.1
Maryland	402	41.6	36.4	22.0	29.5	41.5	29.0	-12.1	5.1	7.0
Massachusetts	483	28.5	44.8	26.7	16.7	33.9	49.5	-11.8	-10.9	22.8
Michigan	867	38.3	40.9	20.8	28.6	39.7	31.7	-9.7	-1.2	10.9
Minnesota	255	35.1	43.7	21.2	27.1	43.4	29.5	-8.0	-0.3	8.3
Mississippi	302	45.4	46.2	8.4	33.9	51.7	14.4	-11.5	5.5	6.0
Missouri	402	41.9	45.8	12.3	31.4	48.8	19.8	-10.5	2.9	7.5
Montana	57	40.3	42.0	17.7	28.9	43.8	27.3	-11.4	1.8	9.6
Nebraska	76	36.3	47.2	16.5	23.8	51.4	24.8	-12.5	4.2	8.3
Nevada	185	44.1	35.9	20.1	33.5	40.1	26.4	-10.6	4.2	6.4
New Hampshire	53	21.7	48.9	29.4	13.8	44.4	41.8	-8.0	-4.5	12.5
New Jersey	437	31.9	45.4	22.6	19.3	47.6	33.0	-12.6	2.2	10.4
New Mexico	191	45.2	43.8	11.0	31.2	50.5	18.2	-14.0	6.8	7.2
New York	1,661	28.3	51.9	19.8	14.1	37.4	48.5	-14.2	-14.5	28.6
North Carolina	755	49.3	33.0	17.8	36.5	40.4	23.1	-12.8	7.4	5.3
North Dakota	25	30.3	44.2	25.4	20.2	40.3	39.5	-10.1	-4.0	14.1
Ohio	843	36.9	47.2	15.9	26.8	47.6	25.7	-10.1	0.4	9.8
Oklahoma	270	45.0	43.9	11.0	34.8	48.1	17.1	-10.2	4.1	6.1
Oregon	444	40.3	35.5	24.3	29.0	38.3	32.7	-11.3	2.9	8.4
Pennsylvania	886	32.3	44.2	23.5	21.2	45.4	33.5	-11.1	1.2	9.9
Rhode Island	99	32.0	43.2	24.8	23.3	39.3	37.4	-8.7	-3.9	12.6
South Carolina	393	50.0	40.5	9.5	34.6	50.2	15.2	-15.4	9.7	5.7
South Dakota	44	37.4	44.5	18.1	26.0	44.2	29.8	-11.4	-0.3	11.7
Tennessee	647	48.0	41.1	10.8	38.6	45.4	16.0	-9.5	4.3	5.2
Texas	1,601	44.2	40.1	15.7	31.0	45.3	23.7	-13.2	5.3	7.9
Utah	90	42.3	43.4	14.2	28.4	47.6	23.9	-13.9	4.2	9.7
Vermont	48	18.9	39.4	41.7	9.5	26.9	63.6	-9.4	-12.5	21.9
Virgin Islands	12	54.5	26.2	19.4	37.7	35.3	27.1	-16.8	9.1	7.7
Virginia	442	45.0	42.4	12.6	32.4	48.1	19.5	-12.6	5.7	6.9
Washington	581	40.2	38.8	21.0	30.2	40.9	28.9	-10.0	2.1	8.0
West Virginia	173	36.4	50.5	13.1	27.6	53.6	18.8	-8.8	3.1	5.7
Wisconsin	417	31.2	38.5	30.3	22.3	35.0	42.6	-8.8	-3.5	12.3
Wyoming	15	40.1	45.4	14.5	29.1	45.1	25.8	-11.0	-0.4	11.3

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Defined as the fiscal year 2014 SNAP net income screen (see Appendix C).

[b] Due to rounding, the sum of individual categories may not match the table total.

Table B.14. Distribution of participants by age and by State

State	Preschool-age children		School-age children		Total children		Non-elderly adults		Elderly adults	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total[a]	6,369	13.9	13,902	30.3	20,271	44.2	20,952	45.7	4,651	10.1
Alabama	119	13.3	277	31.0	396	44.3	430	48.2	67	7.5
Alaska	12	13.9	26	30.2	38	44.0	41	47.5	7	8.5
Arizona	145	14.3	354	35.0	498	49.3	442	43.7	71	7.0
Arkansas	69	14.5	148	31.0	217	45.5	226	47.5	33	7.0
California	744	17.5	1,536	36.1	2,280	53.6	1,782	41.9	193	4.5
Colorado	77	15.5	168	33.8	245	49.3	205	41.2	47	9.4
Connecticut	48	11.1	105	24.5	152	35.6	224	52.4	52	12.1
Delaware	21	14.2	45	29.9	66	44.1	73	49.4	10	6.5
District of Columbia	19	13.3	33	23.3	51	36.6	75	53.7	14	9.7
Florida	438	12.4	947	26.9	1,385	39.3	1,633	46.3	508	14.4
Georgia	296	16.6	515	28.9	811	45.5	826	46.3	146	8.2
Guam	9	20.0	18	38.7	27	58.7	16	35.4	3	5.9
Hawaii	26	13.5	51	26.7	77	40.3	88	46.2	26	13.5
Idaho	33	16.1	69	32.9	102	49.0	90	43.3	16	7.7
Illinois	260	13.3	583	29.8	842	43.1	908	46.4	204	10.4
Indiana	122	13.9	276	31.5	398	45.4	423	48.2	56	6.4
Iowa	57	14.1	124	30.6	181	44.7	194	47.8	30	7.5
Kansas	41	14.0	96	32.7	137	46.7	133	45.3	24	8.0
Kentucky	95	11.9	223	27.8	318	39.6	419	52.2	66	8.2
Louisiana	126	14.4	285	32.6	411	47.1	395	45.2	67	7.7
Maine	23	10.2	53	23.1	76	33.2	121	52.7	32	14.1
Maryland	99	12.7	217	27.9	316	40.6	386	49.5	76	9.8
Massachusetts	83	9.7	222	26.0	305	35.7	396	46.5	152	17.8
Michigan	173	10.4	459	27.6	632	38.0	873	52.5	159	9.5
Minnesota	75	14.4	156	29.9	231	44.3	242	46.4	49	9.4
Mississippi	84	12.9	208	31.7	292	44.6	308	47.1	55	8.4
Missouri	106	12.5	257	30.1	363	42.6	409	48.0	81	9.4
Montana	17	14.2	32	26.2	49	40.4	61	50.5	11	9.1
Nebraska	26	15.0	58	33.7	84	48.7	75	43.7	13	7.6
Nevada	50	13.4	117	31.1	167	44.5	171	45.7	37	9.8
New Hampshire	15	13.9	30	27.5	45	41.3	53	48.8	11	9.9
New Jersey	113	12.9	275	31.5	388	44.4	359	41.1	127	14.5
New Mexico	62	14.6	134	31.5	196	46.1	198	46.5	31	7.3
New York	382	12.6	799	26.3	1,181	38.9	1,260	41.4	599	19.7
North Carolina	208	13.4	455	29.3	663	42.6	741	47.7	151	9.7
North Dakota	9	16.8	15	28.2	24	45.0	24	46.2	5	8.7
Ohio	246	14.2	495	28.6	741	42.8	825	47.7	165	9.5
Oklahoma	76	12.8	187	31.5	262	44.3	286	48.2	44	7.5
Oregon	89	11.3	184	23.5	273	34.9	408	52.1	102	13.0
Pennsylvania	213	11.9	471	26.4	684	38.4	904	50.7	194	10.9
Rhode Island	19	10.8	45	25.9	64	36.7	86	49.3	24	14.0
South Carolina	108	13.0	271	32.6	379	45.5	379	45.5	74	8.9
South Dakota	16	16.1	30	30.3	46	46.4	45	45.6	8	8.1
Tennessee	162	12.5	384	29.5	546	41.9	631	48.4	126	9.7
Texas	687	17.9	1,466	38.2	2,152	56.1	1,336	34.8	349	9.1
Utah	37	16.1	82	36.1	118	52.2	95	41.9	13	5.9
Vermont	12	12.6	20	21.8	32	34.4	45	48.4	16	17.1
Virgin Islands	5	16.6	8	30.2	13	46.8	12	43.9	3	9.3
Virginia	126	13.8	271	29.7	398	43.5	449	49.2	67	7.3
Washington	144	13.2	289	26.6	432	39.9	539	49.7	114	10.5
West Virginia	42	12.0	85	24.0	128	36.0	190	53.6	37	10.4
Wisconsin	101	12.1	238	28.6	339	40.7	407	48.9	86	10.4
Wyoming	6	16.9	12	34.5	18	51.4	15	41.9	2	6.8

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Due to rounding, the sum of individual categories may not match the table total.

Table B.15. Distribution of participants by disability status and by State

State	Children with disabilities		Non-elderly adults with disabilities		Non-elderly individuals with disabilities		Adults age 18 to 49 without disabilities in childless households[a]		Adults age 18 to 49 without disabilities not subject to work requirements or a time limit	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total[b]	1,006	2.2	4,461	9.7	5,467	11.9	4,721	10.3	9,452	20.6
Alabama	20	2.3	107	12.0	128	14.3	91	10.2	199	22.3
Alaska	1	0.8	6	7.4	7	8.2	10	10.9	20	22.9
Arizona	19	1.9	71	7.1	91	9.0	94	9.3	223	22.0
Arkansas	16	3.5	53	11.0	69	14.5	47	9.9	104	21.8
California	2	0.0	46	1.1	48	1.1	565	13.3	922	21.7
Colorado	14	2.9	47	9.4	61	12.3	37	7.5	98	19.7
Connecticut	7	1.6	53	12.3	60	13.9	56	13.0	89	20.8
Delaware	3	2.1	10	6.7	13	8.8	15	10.3	37	24.9
District of Columbia	2	1.6	16	11.5	18	13.2	23	16.5	23	16.7
Florida	104	2.9	298	8.5	402	11.4	491	13.9	611	17.3
Georgia	31	1.7	135	7.6	166	9.3	207	11.6	391	21.9
Guam	0	0.3	0	0.7	1	1.1	2	4.0	12	25.8
Hawaii	1	0.7	15	8.1	17	8.8	22	11.4	39	20.4
Idaho	4	1.9	20	9.5	24	11.4	13	6.0	51	24.2
Illinois	27	1.4	161	8.2	188	9.6	271	13.9	382	19.5
Indiana	28	3.2	102	11.6	130	14.8	79	9.1	201	22.9
Iowa	6	1.5	39	9.6	45	11.1	45	11.1	88	21.8
Kansas	7	2.5	38	13.1	45	15.5	16	5.5	66	22.7
Kentucky	33	4.1	114	14.1	146	18.2	102	12.7	167	20.8
Louisiana	26	3.0	93	10.6	119	13.6	75	8.6	193	22.0
Maine	5	2.1	41	18.1	46	20.2	20	8.7	48	21.1
Maryland	15	1.9	78	10.0	93	11.9	93	11.9	172	22.0
Massachusetts	26	3.1	137	16.1	164	19.2	80	9.4	138	16.2
Michigan	53	3.2	226	13.6	280	16.8	218	13.1	331	19.9
Minnesota	8	1.5	63	12.1	71	13.6	40	7.7	114	21.9
Mississippi	13	2.0	66	10.1	79	12.1	71	10.8	139	21.3
Missouri	21	2.5	104	12.1	125	14.6	83	9.7	189	22.2
Montana	2	1.6	13	10.4	14	12.0	12	10.3	30	24.5
Nebraska	3	1.9	20	11.5	23	13.4	11	6.3	38	22.1
Nevada	4	1.2	33	8.9	38	10.1	45	12.0	71	18.8
New Hampshire	3	3.0	19	17.9	23	20.9	5	4.9	25	22.8
New Jersey	7	0.8	86	9.8	93	10.6	55	6.3	171	19.5
New Mexico	6	1.4	39	9.2	45	10.6	38	9.0	102	23.9
New York	54	1.8	396	13.0	450	14.8	228	7.5	518	17.0
North Carolina	32	2.0	123	7.9	154	9.9	182	11.7	348	22.4
North Dakota	1	1.8	6	12.1	7	13.9	3	6.5	13	24.7
Ohio	46	2.7	236	13.6	282	16.3	138	8.0	376	21.7
Oklahoma	11	1.9	72	12.2	84	14.2	47	8.0	131	22.1
Oregon	11	1.4	86	10.9	97	12.4	117	14.9	152	19.4
Pennsylvania	69	3.9	265	14.9	335	18.8	173	9.7	392	22.0
Rhode Island	6	3.2	26	15.0	32	18.2	20	11.8	30	17.5
South Carolina	12	1.5	74	8.9	86	10.4	75	9.0	180	21.6
South Dakota	1	1.0	11	10.7	12	11.6	7	6.9	24	24.0
Tennessee	24	1.9	134	10.3	158	12.1	161	12.3	281	21.5
Texas	132	3.5	278	7.2	410	10.7	126	3.3	764	19.9
Utah	3	1.4	18	8.0	21	9.4	12	5.4	55	24.3
Vermont	2	2.4	15	16.5	17	18.9	6	6.8	18	19.8
Virgin Islands	0	0.2	0	1.3	0	1.5	3	10.1	7	24.6
Virginia	18	2.0	97	10.6	115	12.6	96	10.5	206	22.6
Washington	20	1.9	122	11.2	142	13.1	162	15.0	208	19.2
West Virginia	9	2.5	60	16.9	69	19.4	35	10.0	79	22.3
Wisconsin	32	3.9	88	10.6	121	14.5	96	11.5	178	21.4
Wyoming	0	0.9	3	8.1	3	9.0	1	4.1	9	26.0

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] With some exceptions, these participants are subject to work requirements and a time limit.

[b] Due to rounding, the sum of individual categories may not match the table total.

Table B.16. Distribution of participants by citizenship status and by State

State	All participants		U.S.-born citizens		Naturalized citizens		Refugees		Other noncitizens		Citizen children living with a noncitizen[a]	
	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total[b]	45,874	100.0	42,258	100.0	1,715	100.0	356	100.0	1,545	100.0	4,133	100.0
Alabama	893	1.9	889	2.1	0	0.0	1	0.3	2	0.1	18	0.4
Alaska	87	0.2	84	0.2	2	0.1	–	–	1	0.1	2	0.0
Arizona	1,011	2.2	931	2.2	24	1.4	4	1.2	51	3.3	165	4.0
Arkansas	476	1.0	473	1.1	1	0.1	0	0.0	3	0.2	22	0.5
California	4,256	9.3	3,729	8.8	249	14.5	24	6.9	254	16.4	1,054	25.5
Colorado	497	1.1	459	1.1	17	1.0	10	2.7	11	0.7	65	1.6
Connecticut	428	0.9	394	0.9	17	1.0	1	0.2	17	1.1	21	0.5
Delaware	149	0.3	144	0.3	2	0.1	0	0.1	2	0.1	8	0.2
District of Columbia	140	0.3	135	0.3	1	0.1	1	0.1	3	0.2	6	0.1
Florida	3,526	7.7	2,850	6.7	304	17.7	42	11.8	330	21.4	308	7.5
Georgia	1,784	3.9	1,718	4.1	25	1.5	17	4.8	23	1.5	111	2.7
Guam	46	0.1	42	0.1	2	0.1	–	–	2	0.1	11	0.3
Hawaii	191	0.4	166	0.4	15	0.9	1	0.1	10	0.6	12	0.3
Idaho	208	0.5	199	0.5	2	0.1	3	0.7	4	0.3	18	0.4
Illinois	1,954	4.3	1,851	4.4	61	3.6	7	1.8	35	2.3	180	4.3
Indiana	877	1.9	858	2.0	8	0.5	4	1.1	7	0.4	42	1.0
Iowa	405	0.9	385	0.9	7	0.4	9	2.6	4	0.3	23	0.6
Kansas	293	0.6	283	0.7	3	0.2	2	0.6	4	0.3	14	0.3
Kentucky	803	1.8	783	1.9	3	0.1	15	4.1	2	0.2	18	0.4
Louisiana	874	1.9	865	2.0	2	0.1	2	0.5	5	0.3	14	0.3
Maine	229	0.5	222	0.5	3	0.2	2	0.7	2	0.1	2	0.0
Maryland	779	1.7	744	1.8	15	0.8	3	0.9	18	1.1	35	0.8
Massachusetts	853	1.9	710	1.7	87	5.1	4	1.1	52	3.3	47	1.1
Michigan	1,664	3.6	1,594	3.8	36	2.1	11	3.1	23	1.5	45	1.1
Minnesota	521	1.1	455	1.1	43	2.5	12	3.3	11	0.7	25	0.6
Mississippi	655	1.4	654	1.5	1	0.0	0	0.1	1	0.0	9	0.2
Missouri	853	1.9	835	2.0	8	0.5	5	1.4	5	0.3	16	0.4
Montana	121	0.3	119	0.3	0	0.0	–	–	1	0.1	0	0.0
Nebraska	172	0.4	159	0.4	4	0.2	6	1.8	3	0.2	12	0.3
Nevada	375	0.8	353	0.8	8	0.5	2	0.6	11	0.7	52	1.2
New Hampshire	108	0.2	103	0.2	1	0.1	2	0.7	1	0.1	2	0.0
New Jersey	874	1.9	721	1.7	93	5.4	4	1.2	56	3.6	112	2.7
New Mexico	426	0.9	402	1.0	6	0.3	0	0.1	17	1.1	36	0.9
New York	3,039	6.6	2,408	5.7	357	20.8	55	15.3	219	14.2	291	7.0
North Carolina	1,555	3.4	1,521	3.6	13	0.8	4	1.1	17	1.1	99	2.4
North Dakota	53	0.1	49	0.1	1	0.0	3	0.9	0	0.0	1	0.0
Ohio	1,732	3.8	1,681	4.0	28	1.7	7	2.0	15	1.0	47	1.1
Oklahoma	592	1.3	579	1.4	4	0.2	3	0.9	6	0.4	16	0.4
Oregon	782	1.7	739	1.7	23	1.3	1	0.3	19	1.2	66	1.6
Pennsylvania	1,782	3.9	1,730	4.1	13	0.7	16	4.5	23	1.5	44	1.1
Rhode Island	174	0.4	153	0.4	11	0.6	2	0.4	9	0.6	13	0.3
South Carolina	832	1.8	824	1.9	1	0.1	3	0.9	4	0.2	27	0.6
South Dakota	99	0.2	96	0.2	1	0.1	2	0.7	1	0.0	2	0.0
Tennessee	1,303	2.8	1,284	3.0	10	0.6	4	1.0	6	0.4	59	1.4
Texas	3,838	8.4	3,522	8.3	105	6.1	32	9.0	178	11.5	699	16.9
Utah	227	0.5	215	0.5	5	0.3	5	1.3	2	0.1	20	0.5
Vermont	92	0.2	90	0.2	1	0.0	1	0.3	0	0.0	0	0.0
Virgin Islands	28	0.1	23	0.1	2	0.1	0	0.0	2	0.1	2	0.0
Virginia	914	2.0	874	2.1	19	1.1	3	0.7	18	1.2	62	1.5
Washington	1,085	2.4	967	2.3	64	3.7	11	3.1	43	2.8	129	3.1
West Virginia	354	0.8	353	0.8	1	0.0	–	–	0	0.0	1	0.0
Wisconsin	831	1.8	804	1.9	7	0.4	10	2.8	10	0.7	52	1.3
Wyoming	35	0.1	35	0.1	–	–	–	–	0	0.0	1	0.0

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Noncitizens may be inside or outside the SNAP unit.

[b] Due to rounding, the sum of individual categories may not match the table total.

– No sample data in this category.

Table B.17. Distribution of noncitizen participants by age and by State

State	Total (000)	Children		Non-elderly adults		Elderly adults	
		Number (000)	Percent	Number (000)	Percent	Number (000)	Percent
Total[a]	1,901	345	18.2	1,071	56.4	484	25.5
Alabama	3	–	–	2	71.3	1	28.7
Alaska	1	–	–	1	59.2	1	40.8
Arizona	56	4	7.5	40	70.9	12	21.6
Arkansas	3	1	19.4	2	73.5	0	7.1
California	278	35	12.6	197	70.9	46	16.5
Colorado	21	5	26.2	9	44.6	6	29.3
Connecticut	17	3	19.4	9	51.6	5	29.0
Delaware	2	1	34.2	1	52.1	0	13.7
District of Columbia	4	1	26.2	2	50.8	1	22.9
Florida	372	46	12.2	233	62.5	94	25.3
Georgia	40	10	26.0	23	57.2	7	16.8
Guam	2	0	7.1	1	42.1	1	50.8
Hawaii	10	3	27.0	4	33.7	4	39.3
Idaho	7	1	14.9	5	69.5	1	15.6
Illinois	42	5	10.8	25	58.8	13	30.4
Indiana	11	1	12.9	7	60.4	3	26.7
Iowa	13	6	43.1	6	47.5	1	9.4
Kansas	7	2	24.0	3	50.9	2	25.2
Kentucky	17	6	33.0	8	48.4	3	18.5
Louisiana	7	2	28.9	4	54.4	1	16.7
Maine	4	1	32.9	2	48.8	1	18.3
Maryland	21	5	25.5	9	43.3	6	31.2
Massachusetts	55	13	23.4	21	37.8	21	38.8
Michigan	34	10	29.4	17	48.1	8	22.5
Minnesota	23	6	25.9	13	59.1	3	15.0
Mississippi	1	0	25.4	0	24.5	1	50.0
Missouri	10	3	35.0	5	47.3	2	17.7
Montana	1	0	15.3	1	62.2	0	22.5
Nebraska	9	3	34.5	6	58.7	1	6.8
Nevada	13	1	7.0	8	62.7	4	30.3
New Hampshire	4	1	32.5	2	55.2	0	12.3
New Jersey	60	12	20.7	31	51.7	17	27.6
New Mexico	18	1	2.9	10	57.5	7	39.6
New York	274	64	23.5	111	40.6	98	36.0
North Carolina	21	5	23.7	12	57.3	4	19.0
North Dakota	3	1	28.7	2	63.2	0	8.1
Ohio	22	5	24.5	13	58.1	4	17.4
Oklahoma	9	2	26.3	6	59.6	1	14.1
Oregon	20	2	9.2	13	63.2	6	27.6
Pennsylvania	39	10	24.7	21	53.6	9	21.7
Rhode Island	10	2	23.4	6	60.1	2	16.6
South Carolina	7	3	44.9	4	55.1	–	–
South Dakota	3	1	36.0	2	53.8	0	10.2
Tennessee	10	2	16.3	6	65.3	2	18.4
Texas	210	35	16.8	110	52.5	64	30.7
Utah	7	2	24.6	4	63.5	1	11.9
Vermont	1	0	27.8	1	51.6	0	20.6
Virgin Islands	2	1	32.8	1	52.7	0	14.5
Virginia	21	4	20.5	11	55.5	5	24.1
Washington	54	9	16.1	33	60.3	13	23.6
West Virginia	0	0	49.0	0	51.0	–	–
Wisconsin	20	7	36.9	10	52.9	2	10.3
Wyoming	0	–	–	0	100.0	–	–

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

[a] Due to rounding, the sum of individual categories may not match the table total.

– No sample data in this category.

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APPENDIX C

FISCAL YEAR 2014 SNAP PARAMETERS

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Table C.1. 2013 HHS poverty income guidelines

Household size	Contiguous United States, Guam, and the Virgin Islands	Alaska	Hawaii
1	$11,490	$14,350	$13,230
2	15,510	19,380	17,850
3	19,530	24,410	22,470
4	23,550	29,440	27,090
5	27,570	34,470	31,710
6	31,590	39,500	36,330
7	35,610	44,530	40,950
8	39,630	49,560	45,570
Each additional member	+4,020	+5,030	+4,620

Source: 78 *Federal Register* 16, January 24, 2013.

Note: HHS issued these numbers, which provide the basis for the fiscal year 2014 SNAP gross and net monthly income eligibility standards.

Table C.2. SNAP maximum allowable gross monthly income eligibility standards in fiscal year 2014

Household size	Contiguous United States, Guam, and the Virgin Islands	Alaska	Hawaii
1	$1,245	$1,555	$1,434
2	1,681	2,100	1,934
3	2,116	2,645	2,435
4	2,552	3,190	2,935
5	2,987	3,735	3,436
6	3,423	4,280	3,936
7	3,858	4,825	4,437
8	4,294	5,369	4,937
Each additional member	+436	+545	+501

Source: U.S. Department of Agriculture.

Note: The fiscal year 2014 SNAP gross monthly income limits were based on the 2013 poverty guidelines issued by HHS (see Table C.1). FNS derived the fiscal year 2014 gross income limits by multiplying the 2013 poverty guidelines by 130 percent, dividing the results by 12, and then rounding up to the nearest dollar.

Table C.3. SNAP maximum allowable net monthly income eligibility standards in fiscal year 2014

Household size	Contiguous United States, Guam, and the Virgin Islands	Alaska	Hawaii
1	$958	$1,196	$1,103
2	1,293	1,615	1,488
3	1,628	2,035	1,873
4	1,963	2,454	2,258
5	2,298	2,873	2,643
6	2,633	3,292	3,028
7	2,968	3,711	3,413
8	3,303	4,130	3,798
Each additional member	+335	+420	+385

Source: U.S. Department of Agriculture.

Note: The fiscal year 2014 SNAP net monthly income limits were based on the 2013 poverty guidelines issued by HHS (see Table C.1). FNS derived the fiscal year 2014 net income limits by dividing the 2013 poverty guidelines by 12 and rounding up to the nearest dollar.

Table C.4. Value of standard SNAP deductions and maximum excess shelter expense deductions in the contiguous United States and outlying areas in fiscal year 2014

Deduction	Contiguous United States	Alaska	Hawaii	Guam	Virgin Islands
Standard deduction					
1 to 2 people	$152	$260	$215	$306	$134
3 people	152	260	215	306	135
4 people	163	260	215	326	163
5 people	191	260	220	382	191
6 or more people	219	274	252	438	219
Maximum excess shelter expense deduction	478	764	644	561	377

Source: U.S. Department of Agriculture.

Notes: The Homeless Household Shelter Estimate was $143.

The Food, Conservation, and Energy Act of 2008 (PL 110-246) eliminated the Maximum Dependent Care Deduction.

Certain State-specific programs did not apply all federal SNAP deductions in the benefit calculation. Only the earnings deduction was used in the benefit calculation for MFIP households. No deductions were used for SSI-CAP households with standardized benefits. States with nonstandardized SSI-CAP benefits used the standard deduction and the excess shelter deduction when calculating benefit levels for SSI-CAP households.

Table C.5a. Value of maximum monthly SNAP benefit in the contiguous United States and outlying areas in October 2013 (ARRA)

Household size	Contiguous United States	Alaska Urban	Alaska Rural I	Alaska Rural II	Hawaii	Guam	Virgin Islands
1	$200	$239	$304	$371	$330	$295	$257
2	367	438	559	680	605	541	472
3	526	627	800	974	867	775	676
4	668	797	1,016	1,237	1,100	985	859
5	793	946	1,207	1,469	1,307	1,169	1,020
6	952	1,135	1,448	1,762	1,568	1,403	1,224
7	1,052	1,255	1,600	1,948	1,734	1,551	1,353
8	1,202	1,434	1,829	2,226	1,981	1,773	1,546
Each additional member	+150	+179	+229	+278	+248	+222	+193

Source: U.S. Department of Agriculture.

Notes: ARRA increased SNAP benefits through October 2013. These maximum benefit values, effective October 1, 2013, through October 31, 2013, were based on 113.6 percent of the cost of the Thrifty Food Plan in June 2008 for a reference family of four, rounded to the lowest dollar increment. (See Table C.5b for maximum benefit values for November 2013 through September 2014.)

Due to the unusual nature of Alaska's terrain and climate, areas outside major urban centers are less accessible to food distributors. Therefore, the value of the maximum benefit was adjusted to account for differences in the estimated cost of the Thrifty Food Plan in various regions of the State. For this purpose, all regions of Alaska were classified as Rural I, Rural II, or Urban.

Table C.5b. Value of maximum monthly SNAP benefit in the contiguous United States and outlying areas in November 2013 through September 2014 (post-ARRA)

Household size	Contiguous United States	Alaska Urban	Alaska Rural I	Alaska Rural II	Hawaii	Guam	Virgin Islands
1	$189	$226	$288	$351	$330	$279	$243
2	347	415	529	644	605	512	446
3	497	594	758	922	867	733	639
4	632	755	962	1,172	1,100	931	812
5	750	896	1,143	1,391	1,307	1,106	964
6	900	1,076	1,372	1,670	1,568	1,327	1,157
7	995	1,189	1,516	1,845	1,734	1,467	1,279
8	1,137	1,359	1,733	2,109	1,981	1,676	1,462
Each additional member	+142	+170	+217	+264	+248	+210	+183

Source: U.S. Department of Agriculture.

Notes: These maximum benefit values were effective November 1, 2013, through September 30, 2014, and were based on 100 percent of the cost of the Thrifty Food Plan in June 2013 for a reference family of four, rounded to the lowest dollar increment. (See Table C.5a for maximum benefit values for October 2013.)

Due to the unusual nature of Alaska's terrain and climate, areas outside major urban centers are less accessible to food distributors. Therefore, the value of the maximum benefit was adjusted to account for differences in the estimated cost of the Thrifty Food Plan in various regions of the State. For this purpose, all regions of Alaska were classified as Rural I, Rural II, or Urban.

Table C.6. Value of minimum monthly SNAP benefit in the contiguous United States and outlying areas in fiscal year 2014

Time period	Contiguous United States	Alaska Urban	Alaska Rural I	Alaska Rural II	Hawaii	Guam	Virgin Islands
October 2013	$16	$19	$24	$30	$26	$24	$21
November 2013–September 2014	$15	$18	$23	$28	$26	$22	$19

Source: U.S. Department of Agriculture.

Note: The minimum benefit, applicable to one- and two-person households, is equal to 8 percent of the maximum benefit for single-person households.

APPENDIX D

SOURCE AND RELIABILITY OF ESTIMATES

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SOURCE AND RELIABILITY OF ESTIMATES

The estimates in this report are derived from a sample of households selected for review as part of the SNAP Quality Control System (SNAP QC). The system is designed to determine (1) if households are eligible for participation in SNAP and are receiving the correct benefit amount or (2) if household participation is correctly denied or terminated. It is based on State samples (from the 50 States, the District of Columbia, Guam, and the U.S. Virgin Islands) of approximately 55,000 participating SNAP households and a somewhat smaller number of denials and terminations. Each month, State agencies select an independent sample of participating SNAP households. Annual required State samples depend upon the size of a State's caseload and generally range from a minimum of 300 to around 1,200 reviews.

Target Universe

The target universe of this study is all participating households (active cases) subject to quality control review in the 50 States, the District of Columbia, Guam, and the Virgin Islands.[1]

Although most participating SNAP households are included in the target universe, certain types of households not subject to review are excluded. Specifically, the universe includes all households receiving SNAP benefits during the review period except those in which all participants (1) died or moved outside the State, (2) received benefits through a disaster certification authorized by FNS, (3) were under investigation for SNAP fraud (including those with pending fraud hearings) and/or were appealing a notice of adverse action, or (4) received restored benefits in accordance with the State manual but were otherwise ineligible. The sampling unit within the universe each month is the active SNAP household as specified in FNS regulations.

Data Editing

The estimates in this report are derived from the fiscal year 2014 SNAP QC datafile, an edited version of the raw datafile generated by the Quality Control System. The raw fiscal year 2014 data are made up of monthly samples from October 2013 through September 2014.

Households with an incomplete Quality Control review or those found ineligible for SNAP benefits were dropped from the edited datafile. Of the 55,066 sample cases in the raw datafile, 2,506 were determined to be not subject to review (Table D.1). Of those cases subject to review, 3,605 did not undergo a complete review because the household failed to cooperate, could not be located, or all members had died or moved. An additional 623 households were found either ineligible for SNAP or eligible for SNAP but ineligible for a positive benefit and, thus, were dropped from the datafile.[2] An additional 82 households were dropped from the file due to internal inconsistencies that could not be resolved, as discussed below. The final unweighted number of households in the fiscal year 2014 SNAP QC file is 48,250. Table D.2 shows the distribution of these unweighted households by State.

[1] Participating households in Guam and the U.S. Virgin Islands have been included in the target universe since fiscal year 1993. Prior to that, the universe excluded households in those areas.

[2] Eligible one- and two-person SNAP units are guaranteed a minimum benefit. However, it is possible for larger units to be eligible for SNAP but have net income high enough that they do not qualify for a positive benefit. The eligible households dropped from the datafile were found by the reviewer to have a benefit overissuance equal to or greater than the recorded benefit.

Table D.1. Number of cases sampled, dropped from the edited file, and included in the edited file, fiscal year 2014

	Fiscal year 2014 SNAP QC sample
Number of cases sampled	55,066
Cases not subject to review	2,506
Cases deselected to correct for oversampling	0
Cases subject to review	52,560
Incomplete cases	3,605
Cases completed	48,955
Households not eligible for SNAP	467
Households not eligible for a positive benefit	156
Households eligible for a positive benefit	48,332
Households dropped due to unresolved inconsistencies	82
Households on the final file	48,250

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Quality Control sample.

Failure to complete reviews for all cases subject to review may bias the sample results if the characteristics of households not reviewed differ significantly from those of reviewed households. In the absence of direct measures of such differences, the ratio of completed reviews to total cases subject to review provides an indication of the magnitude of any potential bias. For fiscal year 2014, the completion rate was 93 percent, 1 percentage point lower than in fiscal year 2013.

Consistent measures of unit size, income, and benefit level are important to any analysis of SNAP households. Inconsistencies may occur in the initial case record information, the transcription and data entry process, or the extraction of SNAP information for the selected months.

To obtain the highest degree of consistency between related variables in the data while maintaining the database's integrity, the reported raw data are edited as described in the *Technical Documentation for the Fiscal Year 2014 SNAP QC Database and QC Minimodel*. For instance, in most cases, a household's net countable income should equal the household's gross countable income minus the total deductions for which the household is eligible, and the SNAP benefit level should equal the household's maximum benefit minus 30 percent of the household's net countable income. Exceptions are households participating in MFIP and SSI-CAP in States with standardized benefit amounts. These households are subject to different eligibility and benefit determination rules, and their data have been edited accordingly. Additionally, if the value of deductions exceeds gross income, net income is equal to zero.

Although most inconsistencies in these basic relationships were resolved in the editing process, the measures could not be reconciled for 82 records in the raw datafile. These 82 records were therefore dropped from the edited datafile.

Table D.2. Unweighted distribution of participating households by State

State	SNAP households	
	Number	Percent
Total	48,250	100.0
Alabama	1,027	2.1
Alaska	574	1.2
Arizona	959	2.0
Arkansas	1,209	2.5
California	895	1.9
Colorado	924	1.9
Connecticut	1,065	2.2
Delaware	942	2.0
District of Columbia	1,035	2.1
Florida	979	2.0
Georgia	1,005	2.1
Guam	469	1.0
Hawaii	944	2.0
Idaho	986	2.0
Illinois	968	2.0
Indiana	965	2.0
Iowa	909	1.9
Kansas	941	2.0
Kentucky	1,052	2.2
Louisiana	1,005	2.1
Maine	995	2.1
Maryland	940	1.9
Massachusetts	927	1.9
Michigan	932	1.9
Minnesota	1,014	2.1
Mississippi	1,062	2.2
Missouri	870	1.8
Montana	824	1.7
Nebraska	882	1.8
Nevada	957	2.0
New Hampshire	795	1.6
New Jersey	996	2.1
New Mexico	1,053	2.2
New York	913	1.9
North Carolina	1,017	2.1
North Dakota	462	1.0
Ohio	965	2.0
Oklahoma	1,023	2.1
Oregon	952	2.0
Pennsylvania	952	2.0
Rhode Island	994	2.1
South Carolina	1,064	2.2
South Dakota	764	1.6
Tennessee	1,019	2.1
Texas	968	2.0
Utah	979	2.0
Vermont	700	1.5
Virgin Islands	304	0.6
Virginia	881	1.8
Washington	980	2.0
West Virginia	953	2.0
Wisconsin	932	1.9
Wyoming	328	0.7

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

Weighting

The estimates for fiscal year 2014 in this report are based on a sample of 48,250 valid observations. The sample records have been weighted to match SNAP Program Operations totals after adjustment to remove households ineligible for benefits as well as those receiving benefits issued through the SNAP disaster assistance program, as these households are not included in the SNAP QC datafile.[27] The weighting procedure matches to SNAP Program Operations totals for (1) the monthly number of participating households by State and stratum, (2) the monthly number of participants by State, and (3) the monthly total benefits issued by State. Table D.3 compares the Quality Control System sample-based estimates to aggregate program participation data for fiscal year 2014.

The fiscal year 2014 weighting methodology is similar to that used for the fiscal year 2003 through fiscal year 2013 SNAP QC datafiles. However, it differs from the weighting methodology used in the development of the SNAP QC datafiles prior to fiscal year 2003.[28] SNAP QC datafiles before fiscal year 2003 are weighted to match the monthly number of SNAP households by State and stratum, unadjusted for ineligible households or the disaster assistance program.

Table D.3. Comparison of program data to edited SNAP QC datafile, fiscal year 2014

	Fiscal year 2014			
Average monthly value	Program data	Adjustments for disaster assistance[a]	Adjustments for ineligible households	Edited SNAP QC datafile
Number of households	22,699,595	67	254,549	22,444,979
Number of participants	46,536,799	168	662,847	45,873,783
Value of benefits	$5,833,236,297	$1,422,841	$142,166,128	$5,689,647,328
Average household size	2.05	2.50	2.60	2.04
Average benefit per person	$125.35	_	$214.48	$124.03

Sources: Fiscal Year 2014 Program Data and SNAP QC datafile.

[a]We adjust households and individuals for disaster SNAP households only. We adjust benefits for disaster SNAP benefits issued to disaster SNAP households as well as replacement benefits issued to qualifying ongoing SNAP households. As a result, the average disaster SNAP benefit per person cannot be calculated from the information in this table.

Comparison to Reported Data

Table D.4 compares the reported and calculated values of selected variables for fiscal year 2014. Reported values and averages reflect those in the SNAP QC datafile before any editing has taken place. Calculated values and averages are based on the edited datafile used for this report.

[27] The adjusted total number of households and benefits is lower than Program Data figures by about 1 and 2 percent, respectively.

[28] Prior to the fiscal year 2009 report, the fiscal year 2003 and fiscal year 2004 SNAP QC datafiles were weighted to match the disaster- and error-adjusted monthly numbers of SNAP households, but not individuals or benefits, by State and stratum.

Table D.4. Comparison of calculated and reported values for selected variables of participating households, fiscal year 2014

		Households with:			
Variable	All households	Earned income	Elderly individuals	Children	Non-elderly individuals with disabilities
Average gross income (dollars)					
Calculated	759	1,221	876	965	1,007
Reported	760	1,221	881	965	1,006
Average net income (dollars)[a]					
Calculated	335	544	407	449	501
Reported	331	539	402	444	495
Average total deduction (dollars)[b]					
Calculated	538	728	544	615	543
Reported	535	730	537	612	542
Average SNAP benefit (dollars)					
Calculated	253	298	129	390	187
Reported[c]	253	298	126	390	188
Percentage with zero gross income					
Calculated	21.9	0.0	7.2	14.1	0.0
Reported	22.0	0.1	7.2	14.2	0.0
Percentage with zero net income					
Calculated	40.6	22.8	21.6	35.8	11.9
Reported	43.3	23.7	27.4	36.8	17.0
Percentage with minimum benefit					
Calculated	6.4	4.8	17.4	1.2	10.1
Reported	6.1	4.5	16.8	1.1	9.6

Source: Fiscal Year 2014 SNAP QC datafile.

[a]Because net income is not used in their benefit determination, 23,481 households participating in MFIP and 565,481 households participating in an SSI-CAP program in States that use standardized SSI-CAP benefits are excluded from this comparison.

[b]Because deductions are not used in their benefit determination, 565,481 SSI-CAP households in States that use standardized SSI-CAP benefits are excluded from this comparison.

[c]Reported benefit adjusted for reported overissuance errors, underissuance errors, and prorated benefits.

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APPENDIX E

SAMPLING ERROR OF ESTIMATES

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SAMPLING ERROR OF ESTIMATES

The estimates of the characteristics of SNAP households in this report are based on a sample of households and, consequently, are subject to statistical sampling error. One indicator of the magnitude of the sampling error associated with a given estimate is its standard error. Standard error measures the variation in estimated values that would be observed if multiple replications of the sample were drawn. The magnitude of the standard error depends upon (1) the degree of variation in the variable within the population from which the sample is drawn; (2) the design of the sample, including such issues as stratification and sampling probabilities; and (3) the size of the sample on which the estimate is based. This appendix presents estimates of the standard errors associated with key statistics and outlines methods for estimating the standard errors of other statistics for which standard errors have not been directly calculated.

Standard Errors

The standard error of an estimated proportion of households (s_p) based on a simple random sample is:

$$(1) \quad s_p = \sqrt{[p(1-p)(N-n)]/[(n-1)N]},$$

where p is the weighted estimate of the proportion, N is the number of households in the population, and n is the sample size.[1] The standard error of an estimated number of households (s_N) based on a simple random sample is:

$$(2) \quad s_N = N s_p .$$

These formulas for the standard errors of estimates based on a simple random sample do not necessarily apply to estimates derived from more complex samples, such as the stratified design of the SNAP QC sample. In this appendix, standard errors calculated using Equations (1) and (2) are referred to as "naive standard errors." Standard errors can be estimated more accurately using a bootstrap method.

The bootstrap method requires the computation of 500 sets of replicate household weights. Each set is calculated using a nonlinear programming method based on a random sample of the SNAP QC datafile. These replicate weights then are used to calculate standard errors. The following discussion presents standard errors of selected estimates that were computed using the bootstrap method. It then

[1] More precisely, n is the sample size corresponding to the population that forms the denominator or "base" of the proportion being estimated. When the base is all SNAP households in fiscal year 2014, n = 48,250. Sample sizes for selected demographic subgroups for fiscal year 2014 are shown in the sample size column of Table E.1. For subgroups not shown in Table E.1, the sample size can be approximated by multiplying the total sample size (48,250) by the ratio of the subgroup population size to the total population size (N). For fiscal year 2014, $\boldsymbol{N}$ = 22,445,000 and there were 4,255,000 elderly households. Thus, the approximate sample size for elderly households in fiscal year 2014 would be calculated as (4,255,000/22,445,000)x(48,250) = 9,147. In this case, the approximation can be compared to the true elderly sample size of 8,802, as shown in Table E.1.

presents a simple method for approximating standard errors of estimates for which individual standard errors have not been computed.

Standard Errors of Estimated Numbers of Households

The standard errors of selected estimates of SNAP households in fiscal year 2014 are shown in Table E.1. These standard errors can be used to compute confidence intervals for the estimated number of households with a particular characteristic.[2] For example, the estimated number of SNAP households that receive the minimum benefit is 1,433,000 (Table A.1) and the corresponding standard error is 32,807 (Table E.1). The 95 percent confidence interval thus extends from 1,367,000 to 1,499,000.[3]

For standard errors not shown in Table E.1, the approximate standard error (S_E) of an estimated number of households for fiscal year 2014 can be calculated using Equation (3):

$$(3) \quad S_E = S_N \times d,$$

where S_N is the naive standard error from Equation (2) above and d is the square root of the design effect for the population subgroup and characteristic of interest from Table E.2. The design effect reflects the loss of precision due to the different sampling rates in different strata of the SNAP QC sample. It is the ratio of the variance computed by the bootstrap method (Table E.1) to the naive variance.[4] When the population subgroup (for example, households with an elderly person) is listed in Table E.2 but the characteristic of interest is not, the average square root of the design effect for the subgroup from the right-hand column of Table E.2 is used. When neither the subgroup nor the characteristic is listed, use the average square root of the design effect for all SNAP households, 1.59.

For example, to estimate the standard error of the number of households containing an elderly person with zero net income, the first step is to obtain the size of the estimate. As shown in Table A.3, 917,000 households with elderly individuals have zero net income. The next step is to calculate the naive standard error. Using Equations (1) and (2), the value is 18,631.[5] Multiplying 18,631 by the square root of the design effect (d), 1.84, from Table E.2 yields an estimated standard error of 34,361.

[2] A confidence interval is a range of values that will contain the true value of an estimated characteristic with a known probability. For instance, a 95 percent confidence interval extends approximately two standard errors above and below the estimated value for a characteristic, and 95 percent of all confidence intervals will contain the true value.

[3] Calculated as: (1,433,000 - (2 x 32,807)) = 1,367,000 and (1,433,000 + (2 x 32,807)) = 1,499,000.

[4] The variance and naive variance are the standard error and naive standard error squared, respectively.

[5] Equation (1):

$$\sqrt{[(917{,}000/4{,}255{,}000)\times(1 - (917{,}000/4{,}255{,}000))\times(4{,}255{,}000 - 8{,}802)]/[(8{,}802 - 1)\times 4{,}255{,}000]} = 0.00438$$

Equation (2): $4{,}255{,}000 \times 0.00438 = 18{,}631$,

where 4,255,000 is the estimated population of elderly households, 917,000 is the estimated population of elderly households with zero net income, 8,802 is the sample size of elderly households (Table E.1), and 18,631 is the standard error.

Standard Errors of Estimated Percentages

Comparing Equations (1) and (2), it is apparent that the standard error of an estimated percentage of households, S_p, is equal to the standard error of the corresponding count of households, S_N, divided by the number of households in the population that forms the base of the percentage:

(4) $S_p = S_N / N$.

For example, Table A.17 shows that, of the 9,789,000 households with children, 1,376,000 (14.1 percent) have no gross income. The standard error (S_N) of the number of households with children with no gross income is 33,995 (Table E.1). To calculate S_p, the standard error of the corresponding percentage estimate, simply divide S_N by the number of households in the population that forms the base of the percentage—in this case, 9,789,000 households with children. The resulting standard error of the percentage estimate is 0.3 percentage points, and the corresponding 95 percent confidence interval extends from 13.4 to 14.8 percent around the point estimate of 14.1 percent.

Equation (4) can also be applied to standard errors not shown in Table E.1. First, calculate the adjusted naive standard error of the number of households using Equation (3). Then, divide the resulting standard error by the size of the population that forms the base of the percentage. Returning to an earlier example—of the 4,255,000 households with elderly individuals, 917,000 (21.6 percent) have zero net income. Dividing the adjusted naive standard error (calculated above as 34,361) by 4,255,000 yields an adjusted naive standard error of the percentage estimate of 0.8 percentage points.

Standard Errors of Estimated Means

The standard errors for selected estimated means for fiscal year 2014 are provided in Table E.3. For example, the standard error of the mean gross income for all SNAP households in fiscal year 2014 is $3.44 (Table E.3) and the mean itself is $759 (Table A.2). Therefore, a 95 percent confidence interval extends from approximately $752 to $766.

Generalized approximation methods such as that used in Equation (3) work well for standard errors of estimated numbers and percentages because the standard errors depend only upon the sample size, the estimated proportion, and the design effects. Generalized methods are less appropriate for standard errors of means because the standard error depends upon the variance as well as the sample size and design effects. Nevertheless, a rough approximation of the magnitude of standard errors of means not included in Table E.3 can be obtained from Table E.4. Table E.4 shows for each variable in Table E.3 the average, minimum, and maximum value of that variable's standard error as a percentage of the variable's mean value. These three values are shown for all SNAP households and for selected subgroups. The standard errors in Table E.4 include design effects.

Table E.1. Standard errors of estimated numbers of SNAP households, fiscal year 2014

	Households (000) with:									
	Zero gross income	Zero net income	Minimum benefits	Earned income	Elderly individuals	Children	School-age children	Non-elderly individuals with disabilities	Sample size	Estimated population (000)
All SNAP households......	74.96	100.55	32.81	80.97	58.73	88.84	68.22	53.70	48,250	22,445
With elderly individuals	20.09	34.40	23.98	17.58	58.73	13.62	13.33	11.14	8,802	4,255
Without elderly individuals	72.29	94.30	23.97	80.90	n.a.	88.29	68.13	53.41	39,448	18,190
With children...........	33.99	51.70	10.67	76.46	13.62	88.84	68.22	33.18	20,910	9,789
With school-age children....................	29.46	46.94	8.45	59.71	13.33	68.22	68.22	31.36	16,247	7,603
Without children.......	65.22	87.69	31.15	38.52	57.20	n.a.	n.a.	46.57	27,340	12,656
With earnings	n.a.	40.27	17.59	80.97	17.58	76.46	59.71	20.64	15,088	7,016
With non-elderly individuals with disabilities................	0.19	21.39	19.11	20.64	11.14	33.18	31.36	53.70	10,805	4,579

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

Note: Standard errors were estimated using the bootstrap method.

n.a. = not applicable.

Table E.2. Square root of design effects (d) for standard errors of estimated numbers or percentages of SNAP households, fiscal year 2014

	Households with:								
Base of estimated number	Zero gross income	Zero net income	Minimum benefits	Earned income	Elderly individuals	Children	School-age children	Non-elderly individuals with disabilities	Average square root of design effect
All SNAP households..........	1.77	2.00	1.31	1.71	1.47	1.75	1.41	1.30	1.59
With elderly individuals.....	1.71	1.84	1.39	1.54	n.a.	1.46	1.49	1.44	1.55
Without elderly individuals.	1.81	2.07	1.37	1.83	n.a.	1.93	1.51	1.36	1.70
With children	1.44	1.59	1.45	2.26	1.46	n.a.	2.42	1.41	1.72
With school-age children....	1.50	1.68	1.35	2.00	1.50	n.a.	n.a.	1.44	1.58
Without children	1.90	2.31	1.33	1.41	1.60	n.a.	n.a.	1.40	1.66
With earnings...............	n.a.	1.68	1.45	n.a.	1.54	3.01	2.11	1.38	1.86
With non-elderly individuals with disabilities	0.60	1.50	1.44	1.48	1.54	1.64	1.61	n.a.	1.40

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

Note: The design effect is the ratio of the variance computed by the bootstrap method to the naive variance for the specific cell of the table. The average square root of design effect for each row is a simple arithmetic average of the values for each cell in the row.

n.a. = not applicable.

Table E.3. Standard errors of estimated means, fiscal year 2014

	Gross income	Net income	Benefits	All deductions	Total resources	Household size	Certification period	Earnings[a]	TANF[a]	SSI[a]	Shelter deduction[a]
All SNAP households..........	3.44	1.41	0.26	2.21	0.99	0.00	0.05	6.54	6.02	4.61	1.70
With elderly individuals…	7.18	6.29	1.50	6.01	3.58	0.01	0.18	37.32	34.54	8.46	6.15
Without elderly individuals……………...	4.16	1.78	0.62	2.32	0.96	0.00	0.05	6.84	6.07	5.48	1.44
With children…………..	5.13	3.86	2.26	3.19	1.21	0.02	0.03	8.84	6.16	10.63	1.91
With school-age children…………………	6.62	5.26	2.76	3.51	1.44	0.03	0.03	11.22	7.74	11.58	2.24
Without children……….	4.99	3.20	0.69	2.81	1.49	0.00	0.08	11.87	28.59	5.08	2.91
With earnings…………..	6.42	5.47	1.94	3.37	1.98	0.02	0.04	6.54	12.24	14.59	2.15
With non-elderly individuals with disabilities……………..	6.86	6.76	2.06	4.32	2.61	0.02	0.14	31.98	13.00	5.59	3.99

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

Note: Standard errors were estimated using the bootstrap method.

[a]For households with a nonzero amount.

Table E.4. Range of standard errors of mean amounts expressed as a percentage of the mean amount, fiscal year 2014

Number of households in base of mean (000)	Standard error as percentage of the mean amount		
	Average[a]	Lowest[b]	Highest[c]
22,445 (All SNAP households)	0.9	0.0	4.4
4,255 (Households with elderly individuals)	3.3	0.8	12.0
9,789 (Households with children)	1.2	0.3	5.1
7,016 (Households with earnings)	1.6	0.4	6.5
4,579 (Households with non-elderly individuals with disabilities)	2.4	0.7	10.3

Source: Fiscal Year 2014 Supplemental Nutrition Assistance Program Quality Control sample.

Note: Standard errors from Table E.3 and mean amounts from applicable text tables.

[a]Average standard error across all 11 variables in Table E.3 expressed as a percentage of the mean amount.

[b]Lowest of the standard errors across all 11 variables in Table E.3 expressed as a percentage of the mean amount.

[c]Highest of the standard errors across all 11 variables in Table E.3 expressed as a percentage of the mean amount.

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APPENDIX F

DATA COLLECTION INSTRUMENT

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U.S. Department of Agriculture - Food and Nutrition Service

QUALITY CONTROL REVIEW SCHEDULE

PRIVACY ACT/PAPERWORK REDUCTION ACT. According to the Paperwork Reduction Act of 1995, no persons are required to respond to a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0584-0299. The time required to complete this collection is estimated to average 1.056 hours per response, including the time to review instructions, search existing data resources, gather the data needed, and complete and review the information collection. This report is required under provisions of 7 CFR 275.14. This information is needed for the review of State performance in determining recipient eligibility. The information is used to determine State compliance, and failure to report may result in a finding of non-compliance.

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1. QC Review Number	2. Case Number	3. State	4. Local Agency	5. Sample Month and Year	6. Stratum

7. Disposition	8. Findings	9.SNAP Allotment Under Review	10. Error Amount	11. Case Classification

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2									
3									
4									
5									
6									
7									
8									

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21. Type of Action

22. Length of Cert. Period #of months

23. Allotment Adjustment

24. Amount of Allotment Adjustment

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26. Receipt of Expedited Service

27. Authorized Representative Used at Application

28. Categorical Eligibility

29. Reporting Requirement

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31. Property (excluding home)

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32b. Status 2nd Vehicle

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You may record information on up to 16 individuals using additional pages.

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You may record income on up to 10 individuals by using additional pages.

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USDA United States Department of Agriculture

Supplemental Nutrition Assistance Program

FY 2016 Income Eligibility Standards

These tables give the Monthly Income Eligibility Standards for Fiscal Year 2016 (Oct. 1, 2015 to Sept. 30, 2016).

Gross Monthly Income Eligibility Standards (130 Percent of Poverty Level)

Household Size	48 States [1]	Alaska	Hawaii
1	$1,276	$1,595	$1,468
2	1,726	2,158	1,986
3	2,177	2,722	2,504
4	2,628	3,285	3,022
5	3,078	3,848	3,540
6	3,529	4,412	4,058
7	3,980	4,975	4,575
8	4,430	5,538	5,093
Each Additional Member	+451	+564	+518

Net Monthly Income Eligibility Standards (100 Percent of Poverty Level)

Household Size	48 States [1]	Alaska	Hawaii
1	$ 981	$1,227	$1,130
2	1,328	1,660	1,528
3	1,675	2,094	1,926
4	2,021	2,527	2,325
5	2,368	2,960	2,723
6	2,715	3,394	3,121
7	3,061	3,827	3,520
8	3,408	4,260	3,918
Each Additional Member	+347	+434	+399

United States Department of Agriculture

Gross Monthly Income Eligibility Standards For Households Where Elderly Disabled Are A Separate Household (165 Percent of Poverty Level)

Household Size	48 States [1]	Alaska	Hawaii
1	$1,619	$2,024	$1,864
2	2,191	2,739	2,521
3	2,763	3,454	3,178
4	3,335	4,169	3,835
5	3,907	4,884	4,493
6	4,479	5,599	5,150
7	5,051	6,314	5,807
8	5,623	7,029	6,464
Each Additional Member	+572	+715	+658

[1] *Includes District of Columbia, Guam, and the Virgin Islands*

Last updated 9/24/15

FLORIDA PUBLIC SERVICE COMMISSION

2016

FACTS & FIGURES OF THE FLORIDA UTILITY INDUSTRY

This publication is a reference manual for anyone needing quick information about the electric, natural gas, telecommunications, and water and wastewater industries in Florida. The facts have been gathered from in-house materials, outside publications, and websites. Every effort has been made to accurately reference the source of the information used. Though most of the data refers specifically to Florida, some data from other states and national averages are included for comparison purposes. If you have questions about this publication, please contact:

Office of Consumer Assistance & Outreach
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850
(850) 413-6482

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WATER & WASTEWATER

Quick Facts

Customers & Rates

Maps

Regulatory Authority

Pursuant to Chapter 366, Florida Statutes (F.S.), as of December 2015, the Florida Public Service Commission (FPSC) has regulatory authority over:

- **5 investor-owned electric companies** (all aspects of operations, including rates and safety)
- **34 municipally owned electric utilities** (limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning)
- **18 rural electric cooperatives** (limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning)

Generating Capacity
(Utility and Non-Utility)
As of December 31, 2014

- Summer: 57,999 Megawatts (MW)
- Winter: 62,133 MW*

Transmission Capability for Peninsular Florida

- Import: Summer: 3,700 MW
  Winter: 3,700 MW
- Export: Summer: 700 MW

* Generating capacity is higher in winter due to thermodynamics/cooling water.
** Export transmission capability is higher in winter due to thermal ratings of lines and seasonal load patterns.

Sources:
Statistics of the Florida Electric Utility Industry, October 2015
http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/Statistics/2014.pdf

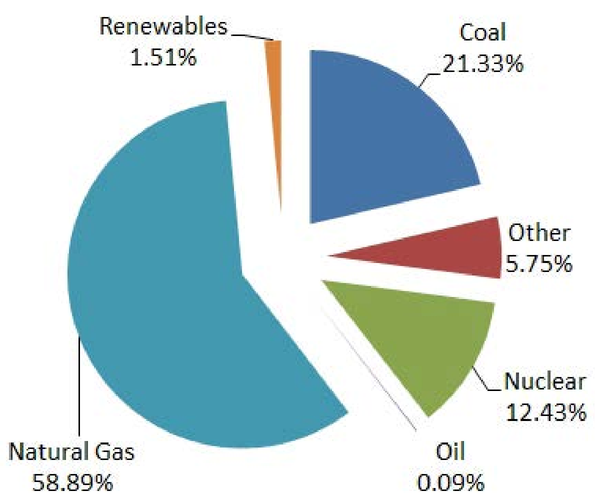
2015 Ten-Year Site Plan Workshop FRCC Studies and Reports

FLORIDA ELECTRIC INDUSTRY

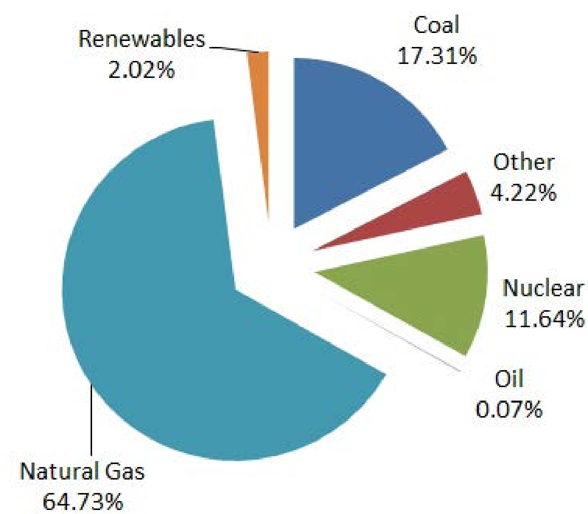
QUICK FACTS

Florida Energy Generation by Fuel Type

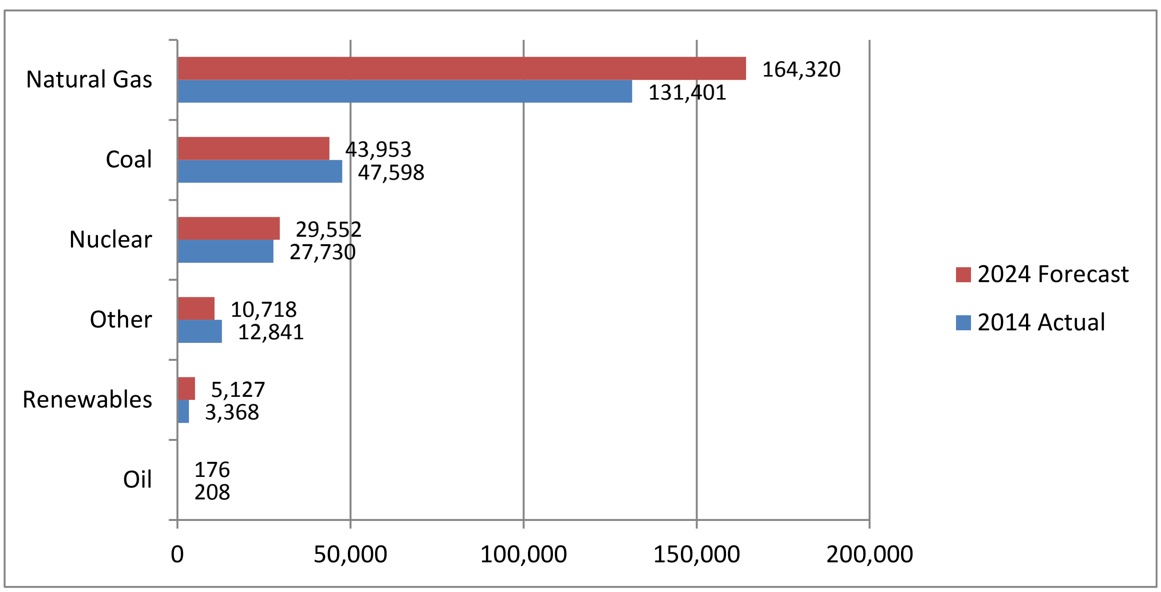
2014
(Actual %)



2024
(Forecast %)

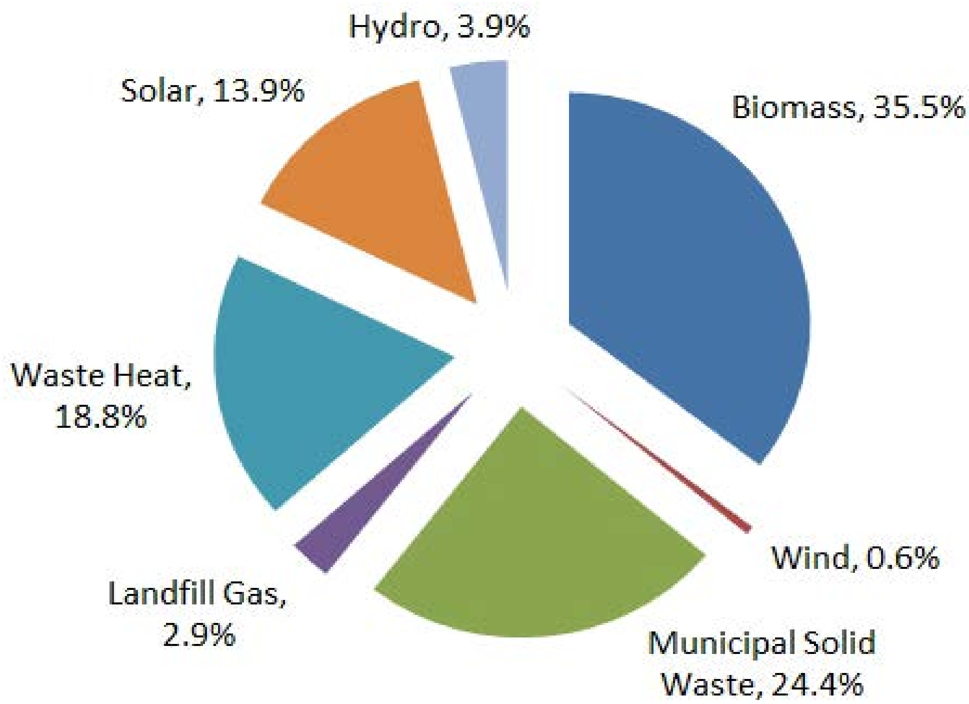


Energy Sources (GWH)



Source:
FRCC 2015 Regional Load & Resource Plan, July 2015
http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2015/FRCC.pdf

Florida's Renewable Capacity in MW(2014)
(Total: 1,638 MW)



Total Florida Renewable Capacity: 1,638 MW
Total Florida Electric Generation Capacity: 57,999 MW (Summer)

Biomass: Material collected from wood processing, forestry, urban wood waste, and agricultural waste.
Landfill Gas: Methane collected from landfills
Waste Heat: Collected in processing phosphate into fertilizer and other products.

Source:
FPSC's *Review of 2015 Ten-Year Site Plans for Florida's Electric Utilities*, November 2015
http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2015/Review.pdf

Average Number of Customers

Average Number of Customers for Investor-Owned Utilities By Class of Service 2014

Utility	Residential	Commercial	Industrial	Other	Total
Florida Power & Light Co.	4,169,028	525,591	10,415	3,795	4,708,829
Florida Public Utilities	23,865	4,382	2	3,023	31,272
Gulf Power Company	386,765	54,749	258	598	442,370
Duke Energy Florida	1,489,502	165,899	2,328	25,725	1,683,454
Tampa Electric Company	623,846	72,647	1,572	8,095	706,161
Total	**6,693,006**	**823,268**	**14,575**	**41,236**	**7,572,085**

Source:
Statistics of the Florida Electric Utility, October 2015, Table 33
http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/Statistics/2014.pdf

Typical Electric Bill Comparisons

Residential Service Provided by Investor-Owned Utilities
December 31, 2015

Utility	Minimum Bill or Customer Charge*	1,000 Kilowatt Hours
Florida Power & Light Company	$7.57	$94.30
Duke Energy Florida	$8.76	$118.55
Tampa Electric Company	$15.00	$106.20
Gulf Power Company	$18.60	$135.81
Florida Public Utilities Company	$14.00	$137.57
Northwest	$14.00	$137.57
Northeast		

Commercial/Industrial Service Provided by Investor-Owned Utilities
December 31, 2015

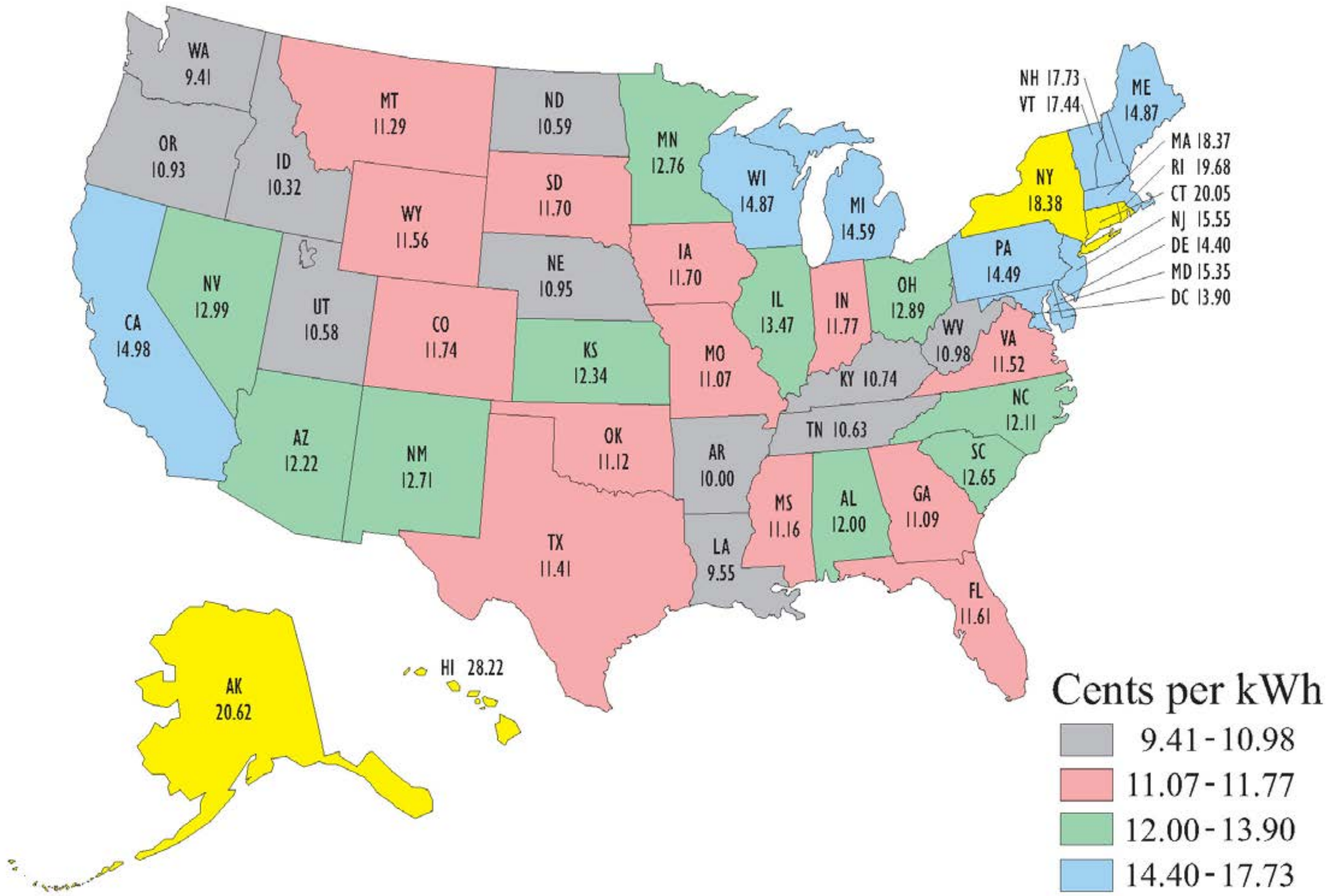
Utility	400,000 Kilowatt Hours 1,000 KW Demand*
Florida Power & Light Company	$31,030
Duke Energy Florida	$34,023
Tampa Electric Company	$34,248
Gulf Power Company	$38,001
Florida Public Utilities Company	
Northwest	$44,562
Northeast	$44,562

* Excludes local taxes, franchise fees, and gross receipts taxes that are billed as a separate line item. Includes cost recovery clause factors effective December 2015.

Note: Typical electric bill comparisons for municipally and cooperatively owned electric utilities are available in the *Comparative Rate Statistics* report available at: http://www.floridapsc.com/Publications/Reports#

Average Residential Price of Electricity by State (2015)

(U.S. Residential Average Price per kWh = 12.73 cents)



Source:
Energy Information Administration's Electric Power Monthly, Table 5.6.A, November 2015
http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_06_a

Nuclear Waste Policy

Florida Power & Light Company (FPL) and Duke Energy Florida (DEF) currently store 2,600 metric tons of radioactive waste called "spent nuclear fuel" in water-filled pools inside containment structures at plant sites. As these pools become filled to capacity, some of the spent fuel will be removed and placed in steel and concrete storage containers (dry casks) on-site.

Federal law requires the U.S. Department of Energy (DOE) to store and ultimately dispose of spent nuclear fuel and high-level radioactive waste in a geologic repository. Since 1983, Florida ratepayers have paid $903.6 million ($1.6895 billion with interest) into the federal nuclear waste fund established to cover the cost of transportation, storage, and disposal of spent fuel. DOE suspended collection of the nuclear waste fee in May 2014.

Florida Nuclear Power Reactors

December 31, 2015

Reactor	Utility	Metric Tons in Spent Fuel Pool	Metric Tons in Dry Cask Storage	NRC License Expires
Crystal River 3	DEF	590	**	2016*
St. Lucie 1	FPL	586	186	2036
St Lucie 2	FPL	484	137	2043
Turkey Point 3	FPL	526	131	2032
Turkey Point 4	FPL	511	131	2033

* Duke Energy Florida filed notification of cessation of operations with the Nuclear Regulatory Commission on February 20, 2013.
** Duke Energy Florida expects to begin storing spent fuel in the dry cask storage system at Crystal River 3 in 2017.

Proposed Nuclear Power Reactor

Reactor	Utility	Estimated In-Service Date
Turkey Point 6	FPL	2027
Turkey Point 7	FPL	2028

Sources:
Responses to information requests provided by Florida Power & Light Company and Duke Energy Florida

Operating Nuclear Reactors

Alabama
Browns Ferry
Units 1, 2, and 3

Joseph M. Farley
Units 1 and 2

Arizona
Palo Verde
Units 1, 2, and 3

Arkansas
Arkansas Nuclear One
Units 1 and 2

California
Diablo Canyon
Units 1 and 2

Connecticut
Millstone
Units 1 and 2

Florida
St. Lucie
Units 1 and 2

Turkey Point
Units 3 and 4

Georgia
Edwin I. Hatch
Units 1 and 2

Vogtle
Units 1 and 2

Illinois
Braidwood
Units 1 and 2

Byron
Units 1 and 2

Clinton

Dresden
Units 2 and 3

Illinois (continued)
La Salle County
Units 1 and 2

Quad Cities
Units 1 and 2

Iowa
Duane Arnold

Kansas
Wolf Creek

Louisiana
River Bend

Waterford

Maryland
Calvert Cliffs
Units 1 and 2

Massachusetts
Pilgrim

Michigan
D. C. Cook
Units 1 and 2

Fermi
Unit 2

Palisades

Minnesota
Monticello

Prairie Island
Units 1 and 2

Mississippi
Grand Gulf

Missouri
Callaway

Nebraska
Cooper

Nebraska (continued)
Fort Calhoun

New Hampshire
Seabrook

New Jersey
Hope Creek

Oyster Creek

Salem
Units 1 and 2

New York
James A. Fitzpatrick

Ginna

Indian Point
Units 2 and 3

Nine Mile Point
Units 1 and 2

North Carolina
Brunswick
Units 1 and 2

McGuire
Units 1 and 2

Shearon Harris

Ohio
Davis-Besse

Perry

Pennsylvania
Beaver Valley
Units 1 and 2

Limerick
Units 1 and 2

Peach Bottom
Units 2 and 3

Pennsylvania (continued)
Susquehanna
Units 1 and 2

Three Mile Island

South Carolina
Catawba
Units 1 and 2

Oconee
Units 1, 2, and 3

H. B. Robinson
Unit 2

Summer

Tennessee
Sequoyah
Units 1 and 2

Watts Bar
Units 1 and 2

Texas
Comanche Peak
Units 1 and 2

South Texas Project
Units 1 and 2

Virginia
North Anna
Units 1 and 2

Surry
Units 1 and 2

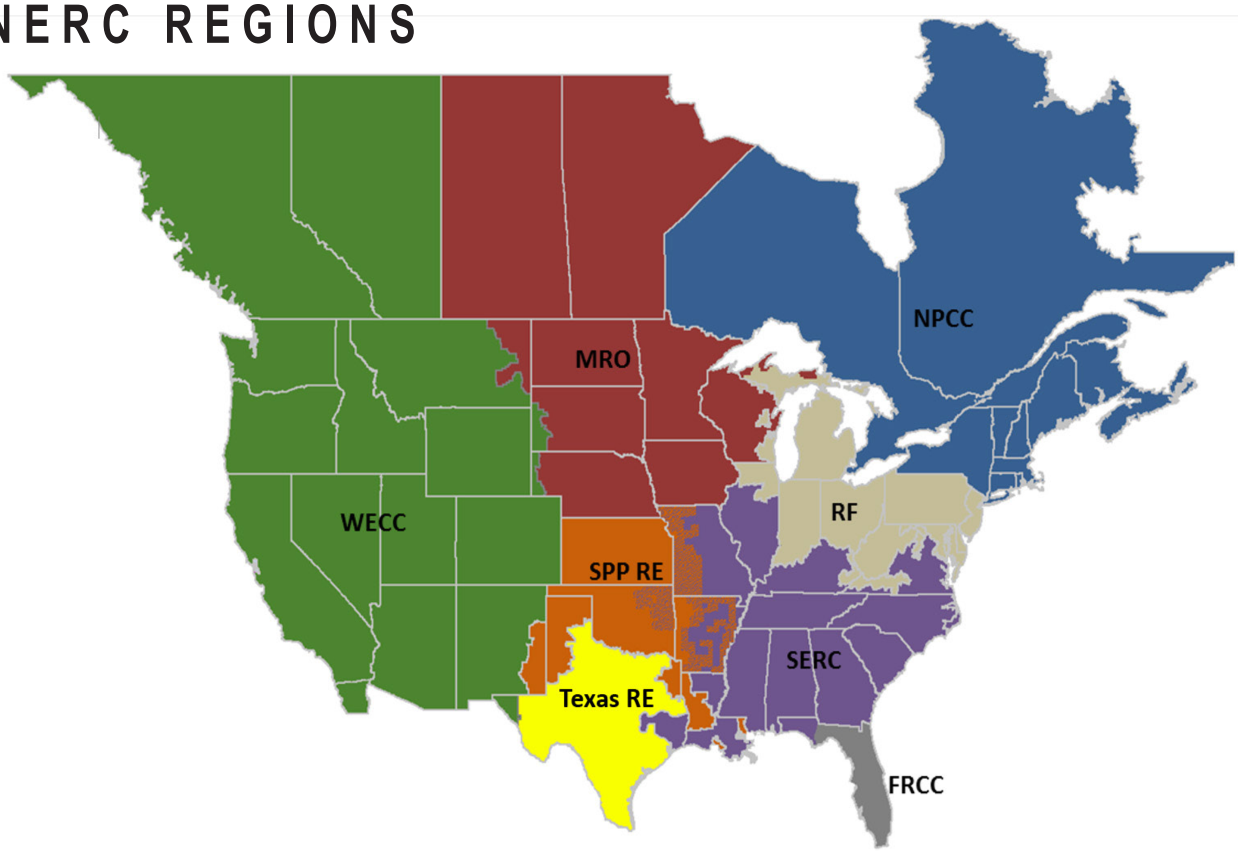
Washington
Columbia
Generating Station

Wisconsin
Point Beach
Units 1 and 2

Source:
Nuclear Regulatory Commission: http://www.nrc.gov/info-finder/region-state/#listAlpha

Reliability Councils

NERC REGIONS

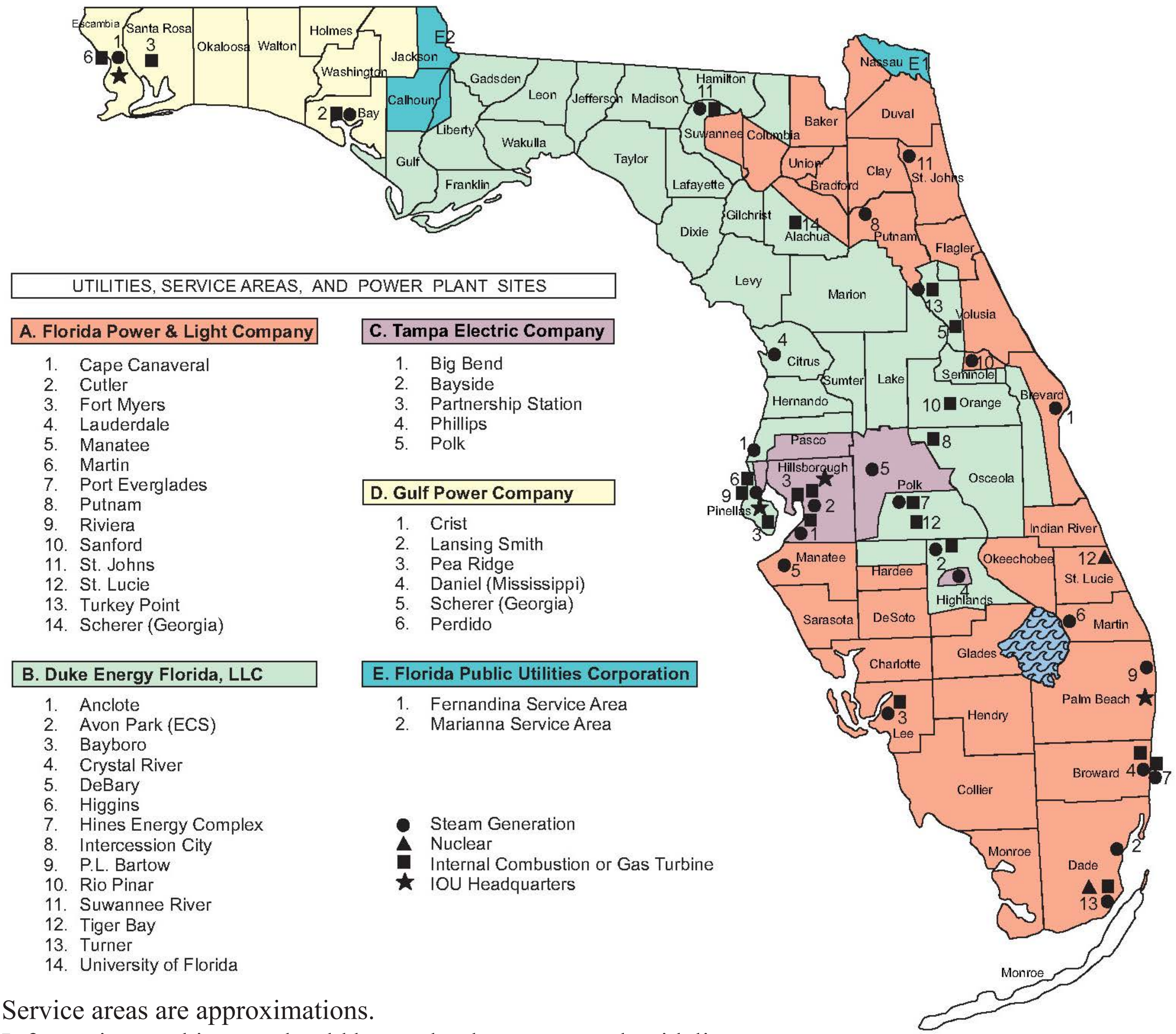


FRCC	Florida Reliability Coordiating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool, RE
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Source: North American Reliability Council
http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx

Investor-Owned Electric Utilities

Approximate Company Service Areas



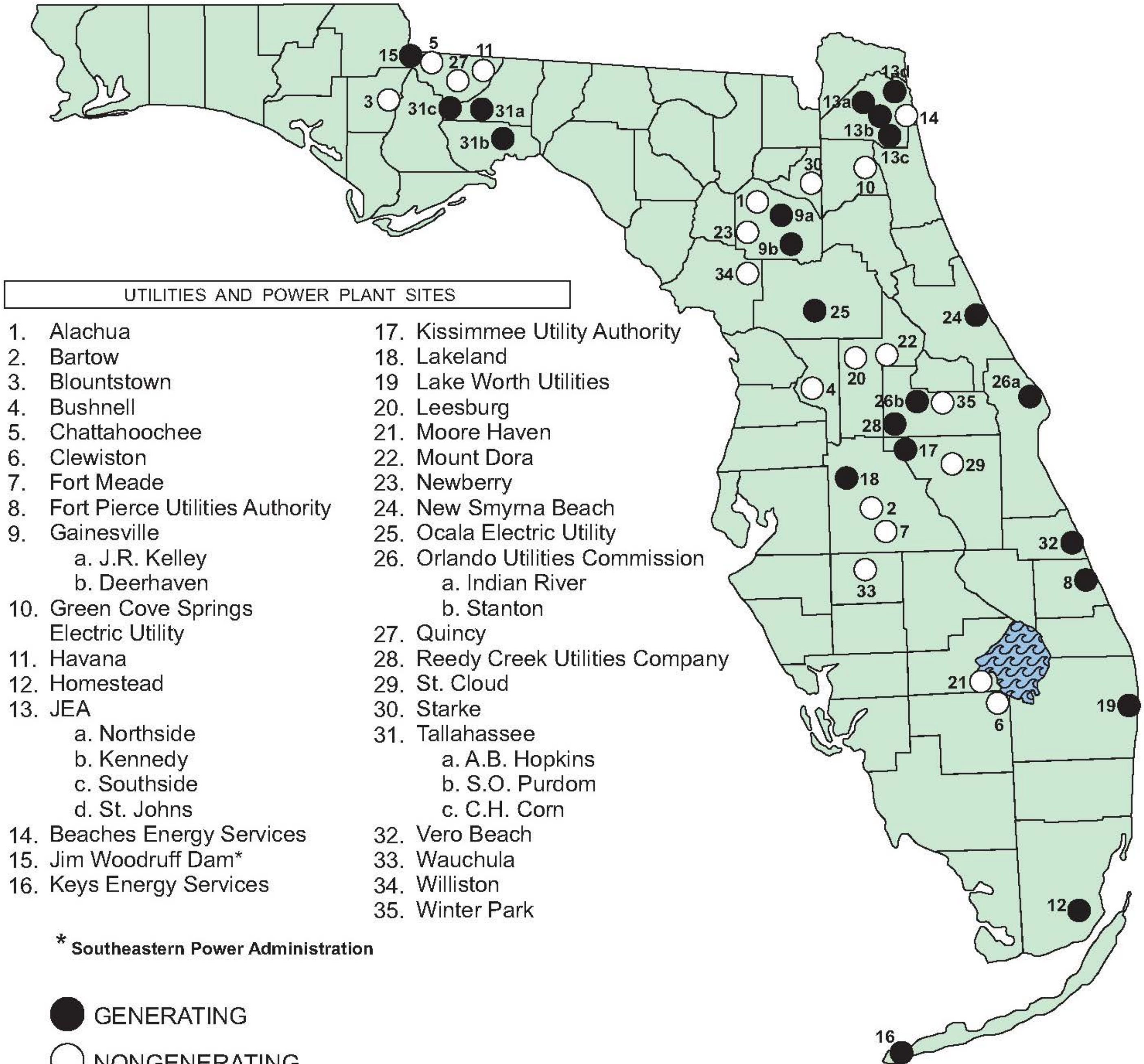
Service areas are approximations.
Information on this map should be used only as a general guideline.
For more detailed information, contact individual utilities.

Source:
Florida Public Service Commission

Additional information about Florida's investor-owned electric utilities is available from:
FPSC's *Statistics of the Florida Electric Utility Industry*, October 2015
http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/Statistics/2014.pdf

Municipal Electric Utilities

Approximate Utility Locations

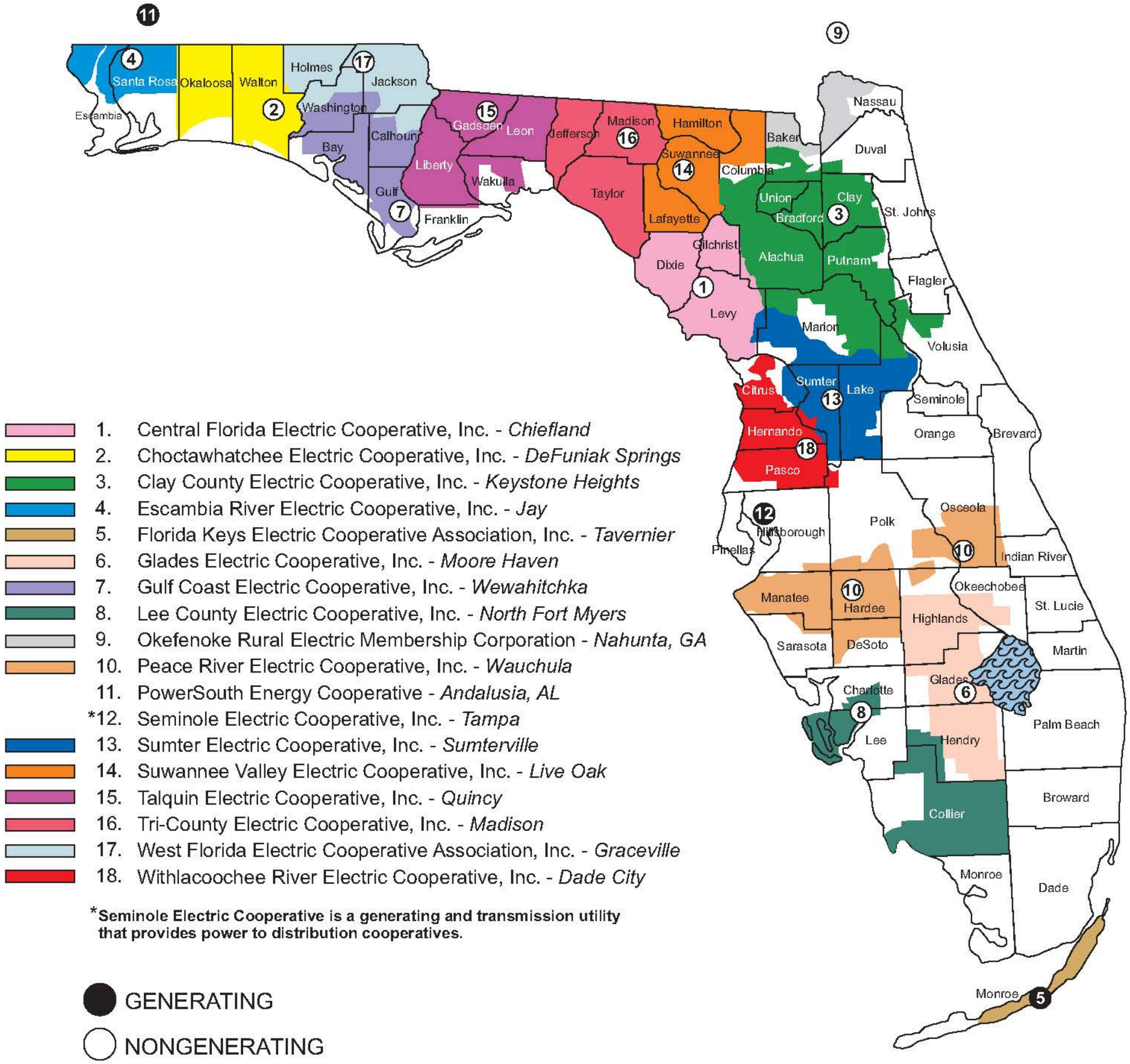


Service areas are approximations.
Information on this map should be used only as a general guideline.
For more detailed information, contact individual utilities.

Source:
Florida Public Service Commission
Additional information about Florida's investor-owned electric utilities is available from FPSC's *Statistics of the Florida Electric Utility Industry*, October 2015
http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/Statistics/2014.pdf

Rural Electric Cooperatives

Approximate Company Service Areas



Service areas are approximations.
Information on this map should be used only as a general guideline.
For more detailed information, contact individual utilities.

Source:
Florida Public Service Commission

Additional information about Florida's investor-owned electric utilities is available from:
FPSC's *Statistics of the Florida Electric Utility Industry*, October 2015
http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/Statistics/2014.pdf

Regulatory Authority

Pusuant to Chapter 366, F.S., as of December 31, 2015, the FPSC has regulatory authority over:

- **8 investor-owned natural gas utilities** (all aspects of operations, including safety)
- **27 municipally-owned natural gas utilities** (limited to safety and territorial boundaries)
- **4 special gas districts** (limited to safety and territorial boundaries)

Transmission

- Natural gas is transported to Florida customers through two major and two small interstate pipelines:

  Major → 1. Florida Gas Transmission Company (FGT)
  2. Gulfstream Natural Gas System

  Small → 1. Gulf South Pipeline Company
  2. Southern Natural Gas

- FGT's pipeline capacity is nearly 3 million cubic feet per day.
- Gulfstream's pipeline capacity is 1.3 billion cubic feet per day.

Sources:
Florida Gas Transmission Company
http://fgttransfer.energytransfer.com/ipost/FGT

Gulfstream Natural Gas System
http://wp.gulfstreamgas.com/

Number of Customers

Number of Customers for Investor-Owned Utilites By Customer Type

December 31, 2014

Utility	Residential	Commercial & Industrial	FTS*	Other**	Total
Florida City Gas	97,993	5,008	2,097	0	105,098
Florida Division of Chesapeake Utilities***	0	0	15,773	0	15,773
Florida Public Utilities	49,510	4,277	1,303	55	55,145
Florida Public Utilities - Ft. Meade Division	653	29	0	0	682
Florida Public Utilities - Indiantown Division***	0	0	704	0	704
Peoples Gas System	319,544	13,069	21,209	67	353,889
Sebring Gas System***	0	0	535	0	535
St. Joe Natural Gas Company	2,721	204	1	1	2,927

* Firm Transportation Service
** Other includes Off System Sales, Interruptible Sales, Natural Gas Vehicle Sales, and Other Sales to Public Authorities
*** Exited the merchant function. All sales are firm transportation customers.

Source:
FPSC, 2014 Annual Reports filed by Natural Gas Utilities

Typical Natural Gas Bill Comparisons

Residential, Commercial, and Industrial Service
Provided by Investor-Owned Utilities
December 31, 2015

	Residential		Commercial		Industrial	
Utility	Minimum Bill or Customer Charge	Therms Sold (20)	Minimum Bill or Customer Charge	Therms Sold (90)	Minimum Bill or Customer Charge	Therms Sold (700)
Florida City Gas	$9.50 - $15	$41.44	$11 - $15	$151.00	$15 - $30	$986.18
Florida Division of Chesapeake Utilities *	$19 - $40	$33.41	$19 - $108	$81.68	$108 - $210	$361.14
Florida Public Utilities	$11.00	$45.04	$20.00	$158.15	$20 - $30	$1,084.69
Florida Public Utilities - Ft. Meade Division	$8.50	$41.61	$17.50	$162.95	$17.50 - $175.00	$924.12
Florida Public Utilities - Indiantown Division *	$9 - $25	$18.62	$9 - $25	$52.27	$25.00	$345.54
Peoples Gas System	$15 - $20	$39.24	$25 - $35	$149.85	$35 - $50	$996.08
Sebring Gas System *	$9 - $35	$23.49	$12 - $35	$74.18	$35 - $150	$399.14
St. Joe Natural Gas Company	$13 - $20	$46.67	$20 - $70	$136.23	$70.00	$924.02

December 2015 gas costs are included for those companies participating in purchased gas adjustment clause: (Florida City Gas, Florida Public Utilities, Florida Public Utilities - Ft. Meade Division, Peoples Gas System, and St. Joe Natural Gas.)

* No longer purchase gas for their customers. These companies deliver gas that the end use customers purchase; therefore, no gas costs are included.

Source: Company Tariffs

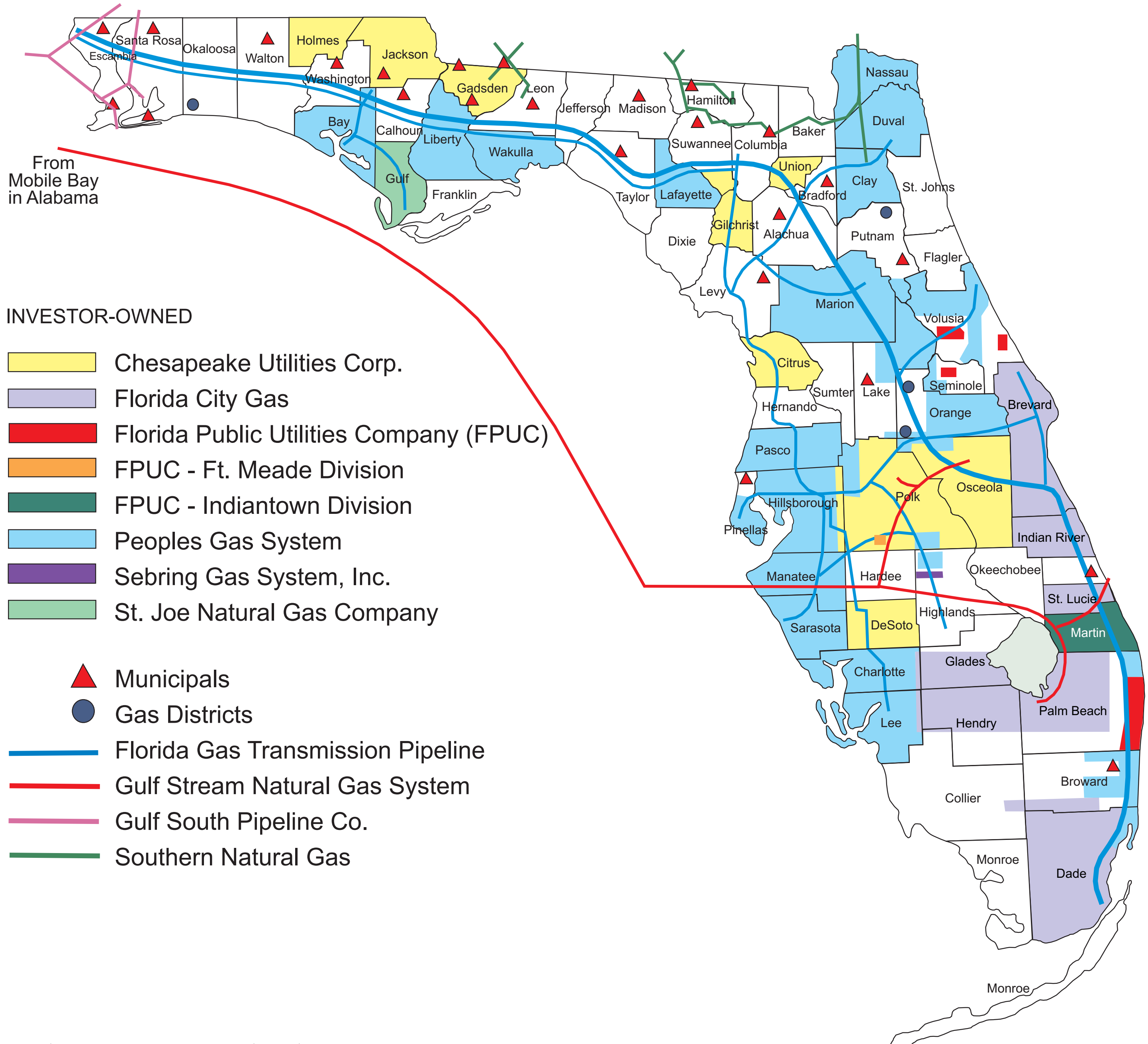
Annual Therm Sales

Annual Therm Sales for Investor-Owned Utilities
December 31, 2014

Utility	Residential	Commercial & Industrial	FTS*	Other**	Total
Florida City Gas	16,441,534	24,917,484	86,004,366	0	127,363,384
Florida Division of Chesapeake Utilities	0	0	116,611,409	0	116,611,409
Florida Public Utilities	12,609,110	25,607,179	27,222,205	6,748,458	72,186,952
Florida Public Utilities - Ft. Meade Division	87,811	79,871	0	0	167,682
Florida Public Utilities - Indiantown Division	0	0	7,560,046	0	7,560,046
Peoples Gas System	71,609,215	36,073,087	430,148,022	1,001,866,945	1,539,697,269
Sebring Gas System***	0	0	1,167,560	0	1,167,560
St. Joe Natural Gas Company	662,071	400,113	461,621	5,060	1,528,865

Source:
FPSC, 2014 Annual Reports filed by Natural Gas Utilities

Natural Gas Companies in Florida



Service areas are approximations.
Information on this map should be used only as a general guideline.
For more detailed information, contact individual utilities.

Source:
FPSC Map
http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/naturalgasutilities.pdf

Regulatory Authority

Pursuant to Chapter 364, F.S., as of December 31, 2015, the FPSC has regulatory authority over:

- **10 incumber local exchange companies (ILECs)**
- **241 competitive local exchange companies (CLECs)**
- **57 pay telephone companies**
- **21 alternative access vendors (AAVs)**
- **14 shared tenant service providers (STS)**

Definitions

- **Incumbent Local Exchange Telecommunications Company (ILEC) -** any company certificated by the Commission to provide local exchange telecommunications service in Florida on or before June 30, 1995.
- **Competitive Local Exchange Telecommunications Company (CLEC)** - any company certificated by the Commission to provide local exchange telecommunications service in Florida on or after July 1, 1995.
- **Pay Telephone Service Company (PATS)** - any certificated telecommunications entity which provides pay telephone service.
- **Alternative Access Vendor (AAV)** - AAVs provide private line service between an entity and facilities at another location, whether owned by the entity or an unaffiliated entity, or access service between an end-user and an interexchange carrier by other than a local exchange telecommunications company. The private line service is dedicated point-to-point or point-to-multipoint service for the transmission of any telecommunication service.
- **Shared Tenant Service (STS)** - Any certificated telecommunications company that provides service which duplicates or competes with local service provided by an existing local exchange telecommunications company and is furnished through a common switching or billing arrangement to tenants by an entity other than an existing local exchange telecommunications company.

Source:
Forida Public Service Commission 2015 Annual Report
http://www.floridapsc.com/Files/PDF/Publications/Reports/General/Annualreports/2015.pdf

FPSC's Telecommunications Terms and Definitions
http://www.floridapsc.com/Telecommunication/TelecomLocalCompetitionTerms

Broadband, VoIP, and Wireless

Broadband is a term describing evolving digital technologies offering consumers integrated access to voice, high-speed data services, video on demand services, and interactive information delivery services. Voice over Internet Protocol (VoIP) and wireless services compete with traditional wireline service and represent a significant portion of today's communications market in Florida. VoIP is not the same as the Internet. It is a technology that allows you to make voice calls using a broadband internet connection instead of a regular telephone line. Broadband service also provides the basis for some VoIP services. These three services are not subject to FPSC jurisdiction.

Broadband

- Approximately 50 percent of fixed broadband connections are at download speeds of 3 megabytes per second (Mbps) or greater; however, 72 percent of those connections are greater than or equal to 200 Mbps.
- Residential subscribership in Florida reached 78 percent as of June 2014, which is above the current national of 73 percent.

VoIP

- As of December 2014, there were an estimated 2.8 million residential VoIP subscribers in Florida, about the same number estimated in 2013.
- The Florida Cable Telecommunications Association (FCTA) reported 2.1 million residential cable digital voice (VoIP) subscribers as of December 2014, about the same number as reported for December 2013.

Wireless

- Wireless suscribers in Florida, as of June 2013, reached 19 million handsets.
- The Centers for Disease Control (CDC) estimates that over 45 percent of households are wireless-only as of December 2014.

Source:
FPSC's *Report on the Status of Competition in the Telecommunications Industry, As of December 31, 2014*
http://www.floridapsc.com/Files/PDF/Publications/Reports/Telecommunication/TelecommunicationIndustry/2015.pdf

Access Lines

An access line is a telephone line extending from the telecommunications company's central office to a point of demarcation, usually on the customer's premises.

Florida Access Lines
As of December 2014

	Residential*	Business*	Total*	Change since 2013
AT&T Florida	694	784	1,478	-21%
CenturyLink FL	609	292	901	-5%
Verizon FL	223	226	449	-12%
Rural ILECs	88	30	118	-12%
CLECs	22	842	864	-22%
Total	**1,636**	**2,174**	**3,810**	**-17%**

* In thousands, rounded to the nearest thousand.

Sources:
FPSC's *Report on the Status of Competition in the Telecommunications Industry, As of December 31, 2014*, Figures 3-3 & 3-4
http://www.floridapsc.com/Files/PDF/Publications/Reports/Telecommunication/TelecommunicationIndustry/2015.pdf

Universal Service Programs

The Federal Communications Commission (FCC) and Congress recognize that telephone service provides a vital link to emergency services, government services, and surrounding communities. To help promote telecommunications service nationwide, the FCC, as directed by Congress, developed the Federal Universal Service Fund (USF). The USF is administered by the Universal Service Administrative Company (USAC). The USF includes the High-Cost, Low-Income, Schools and Libraries, and Rural Health Care Programs.

1 **High-Cost Program.** The federal universal service high-cost program (also known as the Connect America Fund) is designed to ensure that consumers in rural, insular, and high-cost areas have access to modern communications networks capable of providing voice and broadband service, both fixed and mobile, at rates that are reasonably comparable to those in urban areas. The program fulfills this universal service goal by allowing eligible carriers who serve these areas to recover some of their costs from the federal Universal Service Fund.

2 **Low-Income Program.** Provides telephone service discounts to qualifying low-income consumers. It offers benefits through the Lifeline Assistance program:

- **The Lifeline Assistance Program:** Provides a monthly credit of at least $9.25 on basic monthly service or the option of receiving a free Lifeline cell phone and monthly minutes at the primary residence for qualified telephone subscribers. The telephone subscriber may receive a credit less than $9.25 if the subscriber's bill for basic local telephone service is less than that amount.

- **Tribal Benefits:** Residents living on federally recognized tribal lands may receive a one-time discount of up to $100.00 in Link-Up support and enhanced Lifeline support (up to an additional $25.00 in support beyond current levels). Link-Up helps income-eligible consumers on tribal lands with initial installation or activation of a wireline or wireless telephone for the primary residence.

- **Monthly Lifeline Credit:** Under the FCC's rules, monthly federal Lifeline support consists of at least a $9.25 monthly credit on basic monthly service or the option of receiving a free Lifeline cell phone and monthly minutes. Eligible subscribers living on tribal lands can receive a monthly discount of up to $34.25 ($9.25 plus an additional $25).

Low-Income Program (continued)

▲ **Customer Eligibility:** Customers with annual incomes up to 150 percent of the federal poverty guidelines may be eligible to participate in the Lifeline program. In addition, eligibility is determined by customer enrollment in any one of the following programs:

> Temporary Cash Assistance (TCA)*

> Supplemental Security Income (SSI)

> Supplemental Nutritional Assistance Program (SNAP)

> Medicaid

> Federal Public Housing Assistance (Section 8)

> Low-Income Home Energy Assistance Program (LIHEAP)

> National School Lunch Program's Free Lunch Program

> Bureau of Indian Affairs Programs**

3 **Schools and Libraries (or E-Rate) Program.** Helps to ensure that the nation's classrooms and libraries receive access to the vast array of educational resources that are accessible through the telecommunications network. While funding for the program is capped, the FCC has included an index for inflation to preserve the purchasing power of the program. Recently, the FCC increased the annual cap from $2.4 billion to $3.9 billion. The E-Rate program offers the following benefits:

▲ Eligible schools and libraries receive discounts on telephone service, Internet access, and internal connections (i.e., network wiring) within school and library buildings.

▲ The discounts range from 20 percent to 90 percent, depending on the school's eligibility for the National School Lunch program (or a federally approved alternative mechanism) and whether or not the school or library is located in an urban or rural area.

* Known as Temporary Assistance to Needy Families (TANF) for federal Universal Service purposes.
** Eligible consumers living on tribal lands qualify for Link-Up and Lifeline if they participate in one of the following federal assistance programs: (1) Tribal TANF, (2) National School Lunch Free Lunch Program, or (3) Head Start Subsidy.

4 **Rural Health Care Program.** Helps to link health care providers located in rural areas to urban medical centers so that patients living in rural America will have access to the same advanced diagnostic and other medical services that are enjoyed in urban communities. Funding is capped at $400 million annually. This program offers many benefits:

▲ Public and non-profit health care providers in rural areas can receive discounts on monthly telecommunications charges, installation charges, and long distance Internet connection charges.

▲ Rural health care providers are using funds from this program for a variety of patient services, such as transmitting x-rays from remote areas to be read by health care professionals and experts in urban areas.

▲ The FCC has augmented the existing support with a pilot program to fund the construction of dedicated broadband networks that connect health care providers in a state or region. This program will provide funding for up to 85 percent of an applicant's costs of deploying a dedicated broadband network, including any necessary network design studies, as well as the costs of advanced telecommunications and information services that will ride over this network. Participants deploying dedicated broadband health care networks would also have the option of connecting those systems to Internet-2, National LambdaRail, or the public Internet.

▲ Eligible entities include:

> post-secondary educational institutions offering health care instruction, including teaching hospitals and medical schools
> community health centers or health centers providing health care to migrants
> community mental health centers
> local health departments or agencies
> not-for-profit hospitals
> rural health clinics

Source:
Federal Communications Commission
http://www.fcc.gov/cgb/consumerfacts/universalservice.html

Universal Service Program Developments in Florida

Low-Income Program

▲ **Coordinated Enrollment Process** In 2006, FPSC and the Department of Children and Families (DCF) staff developed a process whereby potential Lifeline customers, once certified through a DCF program, could receive Lifeline discounts. From the perspective of the client, the coordinated enrollment process established by the FPSC and DCF is seamless, from filling out the DCF web application to receiving Lifeline discounts.

The coordinated enrollment process entails the DCF client checking a "yes" or "no" box. DCF then forwards the names of the clients who have chosen and been approved for Lifeline, along with their relevant enrollment information, to the FPSC. The FPSC electronically sorts the information by eligible telecommunications carrier (ETC) and places the names on a secure Web site for retrieval and enrollment by the appropriate ETC.

▲ **Lifeline Annual Recertification** All ETCs are now required to perform an annual recertification of their Lifeline subscribers to verify their ongoing eligibility. Subscribers failing to respond to recertification efforts must be de-enrolled from Lifeline. ETCs may contact and receive recertification responses from subscribers in writing, by phone, by text message, by e-mail, by Interactive Voice Response, or otherwise through the internet using an electronic signature. If an ETC is unable to recertify a subscriber because the subscriber did not respond to the recertification request, the ETC must de-enroll the subscriber. If an ETC receives a response that the subscriber is no longer eligible, the subscriber must be de-enrolled within five business days, and offered transitional Lifeline benefits for up to 12 months.

▲ **National Lifeline Accountability Database (NLAD)** The FCC directed the Universal Service Administrative Company to establish a database to both eliminate existing duplicative support and prevent duplicative support in the future. To prevent waste in the Universal Service Fund, the FCC created and mandated the use by ETCs of a National Lifeline Accountability Database to ensure that multiple ETCs do not seek and receive reimbursement for the same Lifeline subscriber. The NLAD conducts a nationwide real-time check to determine if the consumer, or another person at the address of the consumer, is already receiving a Lifeline-supported service.

Source:
FPSC's *Number of Customers Subscribing to Lifeline Service and the Effectiveness of Procedures to Promote Participation*, December 2015
http://www.floridapsc.com/Files/PDF/Publications/Reports/Telecommunication/LifelineReport/2015.pdf

Low-Income Program (continued)

- ▲ **Eligible Telecommunications Carriers (ETC)** A carrier that is granted ETC status is eligible to receive federal universal service support pursuant to FCC rules. To qualify as an ETC, a common carrier must offer services that are supported by federal universal service support mechanisms either using its own facilities or using a combination of its own facilities and another carrier's resold service. Additionally, the carrier must advertise the availability of such services and charges using media of general distribution. As of June 2015, Florida had 21 ETCs, comprised of 10 incumbent local exchange companies, 8 competitive local exchange companies, and 4 wireless companies. FCC rules allow state commissions, upon their own motion or upon request, to designate a common carrier that meets certain requirements as a landline ETC. As of July 2012, the Federal Communications Commission approves wireless providers applying for ETC designation in Florida. As of June 2015 there were 35 Florida ETC wireless petitions pending at the FCC.

- ▲ **Income Eligibility** Section 364.10(2)(a), F.S., allows any local exchange company designated as an ETC with more than 1 million access lines and any commercial mobile radio service provider designated as an ETC carrier pursuant to 47 U.S.C. §214(e), upon filing a notice of election to do so with the Commission, to provide Lifeline service to any customer who meets an income eligibility test of 150 percent or less of the federal poverty income guidelines. All other ETCs must use 135 percent or less of the Federal Poverty Level guidelines for income eligibility.

Universal Service Support Mechanisms by Program for Florida

2014
(Annual Payments and Contributions in Thousands)

Program	Payments from USAC	Estimated Contributions to USAC	Estimated Net Dollar Flow
High-Cost	$63,601	$232,510	($168,908)
Low-Income	$106,617	$103,379	$3,238
Schools & Libraries	$81,541	$141,342	($59,801)
Rural Health Care	$185	$12,019	($11,834)
Administrative Expense		$7,407	$7,407)
Total	**$251,944**	**$496,657**	**($244,712)**

2013
(Annual Payments and Contributions in Thousands)

Program	Payments from USAC	Estimated Contributions to USAC	Estimated Net Dollar Flow
High-Cost	$65,341	$265.968	($200,627)
Low-Income	$101,373	$114,791	($13,418)
Schools & Libraries	$89,269	$140,752	($51,483)
Rural Health Care	$282	$10,151	($9,869)
Administrative Expense		$6,881	($6,881)
Total	**$256,265**	**$538,543**	**($282,278)**

2012
(Annual Payments and Contributions in Thousands)

Program	Payments from USAC	Estimated Contributions to USAC	Estimated Net Dollar Flow
High-Cost	$59,281	$268,520	($209,239)
Low-Income	$118,154	$141,767	($23,613)
Schools & Libraries	$80,450	$143,625	($63,175)
Rural Health Care	$450	$1,064	($9,607)
Administrative Expense		$7,172	($7,172)
Total	**$258,342**	**$571,148**	**($312,806)**

Source:
Federal Communications Commission's *Universal Service Monitoring Reports*
https://transition.fcc.gov/wcb/iatd/monitor.html

Universal Service Support Mechanisms by State (2014)

State	Payments from USAC (in Thousands)	Estimated Contributions to USAC (in Thousands)	Estimated Net Dollar Flow
Alabama	$164,459	$118,102	$46,357
Alaska	$314,912	$19,703	$295,209
American Samoa	$4,274	$700	$3,575
Arizona	$194,132	$160,889	$33,243
Arkansas	$128,596	$69,019	$59,577
California	$581,185	$860,639	($279,454)
Colorado	$104,790	$146,549	($41,759)
Connecticut	$30,658	$107,376	($76,718)
Delaware	$9,391	$26,232	($16,841)
Dist. of Columbia	$13,660	$45,702	($32,042)
Florida	**$251,944**	**$496,657**	**($244,712)**
Georgia	$268,633	$262,668	$5,964
Guam	$11,614	$3,964	$7,650
Hawaii	$34,965	$42,904	($7,938)
Idaho	$52,524	$37,890	$14,633
Illinois	$265,963	$327,141	($61,177)
Indiana	$157,827	$150,279	$7,548
Iowa	$152,004	$74,382	$77,622
Kansas	$176,957	$67,737	$109,220
Kentucky	$188,060	$102,829	$85,231
Louisiana	$165,016	$110,174	$54,842
Maine	$44,479	$36,025	$8,454
Maryland	$55,891	$171,382	($115,491)
Massachusetts	$69,051	$186,538	($117,487)
Michigan	$162,965	$228,159	($65,194)
Minnesota	$149,969	$140,486	$9,483
Mississippi	$237,256	$64,239	$173,017
Missouri	$156,490	$148,181	$8,309
Montana	$101,915	$27,165	$74,751
Nebraska	$88,426	$54,562	$33,863
Nevada	$53,719	$70,418	($16,699)
New Hampshire	$15,573	$37,074	($21,501)
New Jersey	$94,859	$250,777	($155,918)
New Mexico	$119,122	$47,684	$71,438
New York	$278,503	$532,216	($253,712)
North Carolina	$216,238	$250,660	($34,422)
North Dakota	$103,105	$19,004	$84,102
Northern Mariana	$2,204	$816	$1,387
Ohio	$187,723	$278,524	($90,802)
Oklahoma	$325,587	$88,722	$236,865
Oregon	$99,814	$93,152	$6,662
Pennsylvania	$213,938	$344,628	($130,690)
Puerto Rico	$172,976	$82,893	$90,083
Rhode Island	$13,764	$26,931	($13,168)
South Carolina	$175,214	$117,869	$57,346
South Dakota	$85,247	$22,151	$63,095
Tennessee	$152,406	$159,956	($7,550)
Texas	$532,047	$559,963	($27,916)
Utah	$50,136	$65,988	($15,852)
Vermont	$22,582	$18,887	$3,696
Virgin Islands	$20,757	$6,179	$14,578
Virginia	$144,213	$232,939	($88,726)
Washington	$130,160	$166,485	($36,325)
West Virginia	$76,483	$52,697	$23,786
Wisconsin	$184,620	$143,751	$40,869
Wyoming	$46,457	$15,739	$30,718
Total	$7,855,451	$7,974,372	($118,921)

* Estimated contributions include an administrative cost of approximately $119 million.

Source: Federal Communications Commission's *2015 USF Monitoring Report*, Table 1.9
http://transition.fcc.gov/Daily_Releases/Daily_Business/2016/db0316/DOC-337019A1.pdf

Telephone Subscribership

Percentage of Households with Telephone in Unit

	2010	2011	2012	2013	2014
Florida	93.7%	93.2%	94.2%	93.5%	94.1%

Lifeline Subscribership

Lifeline Assistance Subscribers in Florida

Date	Lifeline Enrollment	Eligible Households	Participation Rate
6/2008	183,972	1,186,015	15.5%
6/2009	618,774	1,185,516	52.2%
6/2010	642,129	1,422,837	45.1%
6/2011	943,854	1,690,512	55.8%
6/2012	1,035,858	1,864,183	55.6%
6/2013	918,245	1,952,890	47.0%
6/2014	957,792	1,930,106	49.6%
6/2015	833,612	2,011,166	41.4%

Source:

United States Department of Agriculture Supplemental Nutrition Assistance Program: Number of Households Participating June 2015

FPSC's *Number of Customers Subscribing to Lifeline Service and the Effectiveness of Procedures to Promote Participation*, December 2015
http://www.floridapsc.com/Files/PDF/Publications/Reports/Telecommunication/LifelineReport/2015.pdf

Lifeline Subscribership

Lifeline Subscribership by Eligible Telecommunications Carriers
As of June 2015

Company	Access Lines Subscribed to Lifeline Service
SafeLink**	470,695
Assurance**	208,902
i-wireless/Access**	106,440
AT&T	18,302
CenturyLink	16,163
Verizon	4,721
Windstream	2,746
T-Mobile**	2,110
Fairpoint	671
Cox Telecom*	659
NEFCOM	452
TeleCircuit*	337
TDS Telecom	264
Non-ETC Reseller	195
Global Connection*	194
Budget Phone*	161
Knology d/b/a WOW*	138
ITS Telecom	80
Frontier	46
FLATEL*	23
Smart City	7
Total	**833,612**

Source:
FPSC's *Number of Customers Subscribing to Lifeline Service and the Effectiveness of Procedures to Promote Participation*, December 2015
http://www.floridapsc.com/Files/PDF/Publications/Reports/Telecommunication/LifelineReport/2015.pdf

Regulatory Authority

Pursuant to Chapter 367, F.S., as of December 2015, the FPSC has jurisdiction over 146 investor-owned water and/or wastewater utilities in 37 of Florida's 67 counties.

Use of Reclaimed Water Data for 2014*

- Approximately 727 mgd** of reclaimed water from these facilities was reused for beneficial purposes and represents approximately 44% of the total domestic water flow in the state.

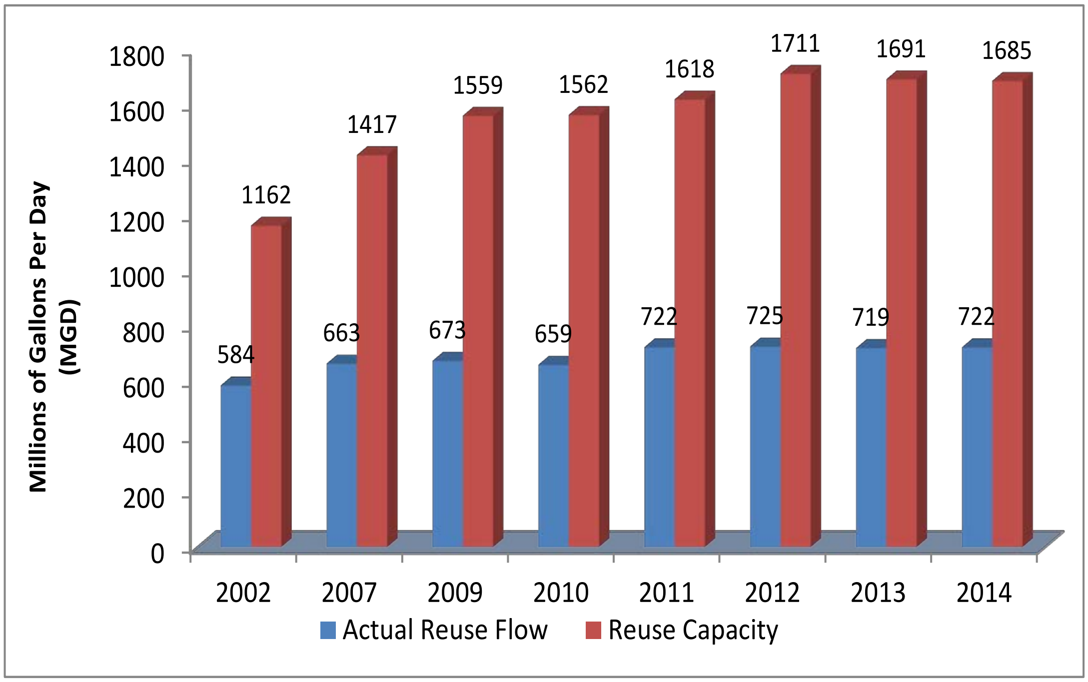
- The 1,685 mgd of reuse capacity represents approximately 65% of the total domestic wastewater treatment capacity in the state.

* Most current data available as of September 2015
** Million gallons per day

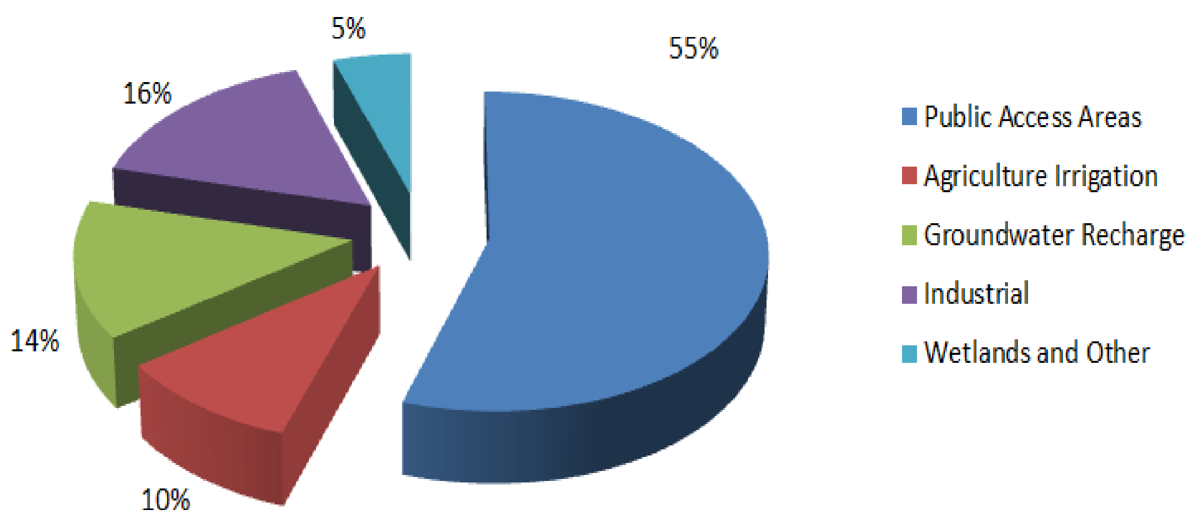
Source:
Florida Department of Environmental Protection's *2014 Reuse Inventory Report*, July 2015 (Revised September 21, 2015)
http://www.dep.state.fl.us/water/reuse/docs/inventory/2014_reuse-report.pdf

Florida's Reuse Growth

Millions of Gallons Per Day (mgd)



Reclaimed Water Utilization (2014)



Source: Florida Department of Environmental Protection's *2014 Reuse Inventory Report*, July 2015 (Revised September 21, 2015)
http://www.dep.state.fl.us/water/reuse/docs/inventory/2014_reuse-report.pdf

Utility Classifications

The National Association of Regulatory Utility Commissioners uses three classes to define the size of water and wastewater utilities:

Class A	Utilities having annual water or wastewater revenues of $1,000,000 or more
Class B	Utilities having annual water or wastewater revenues of $200,000 or more but less than $1,000,000
Class C	Utilities having annual water or wastewater revenues of less than $200,000

• A Class C utility may serve as few as 50 customers, while a Class A utility serves thousands.

• The number of customers served may be obtained from each utility's annual report filed at the FPSC and available online at http://www.floridapsc.com/UtilityRegulation/CompaniesRegulatedByPSC.

Rate Structure

• The base facility charge and gallonage charge rate structure is the most common rate structure used by FPSC-regulated water and wastewater utilities.

• The base facility charge is a flat charge that recovers the fixed costs of utility service that remain the same each month regardless of consumption.

• The gallonage charge recovers the variable costs associated with the utility service such as electricity, chemicals, and labor.

• The gallonage charge is assessed for each 1,000 gallons of water that is registered on the customer's meter.

• Inclining block rate structures are used to encourage water conservation. (The inclining block is similar to the base facility charge and gallonage charge rate structure, but includes additional gallonage charges for higher levels or blocks of usage.)

Residential Wastewater Gallonage Cap

• A maximum (or cap) is set on the number of gallons of water consumption a customer is billed for wastewater service.

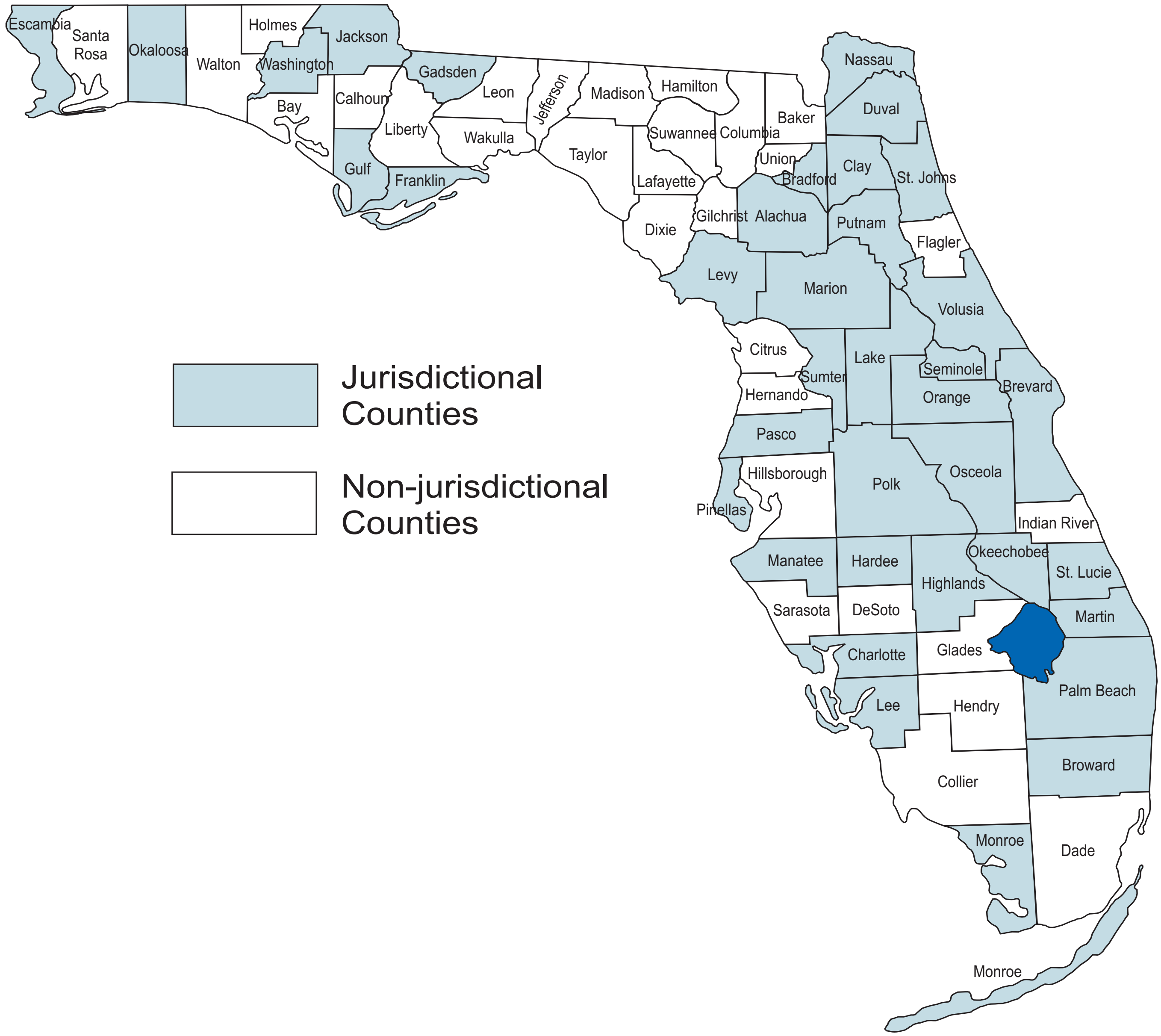
• The monthly cap is normally between 6,000 and 10,000 gallons.(Any water consumption over that amount is generally considered to be used for purposes such as irrigation or washing cars.)

Water & Wastewater Utility Rates

• The rates charged by all water and wastewater utilities under the Commission's jurisdiction are shown in alphabetical order by county in the FPSC's *Comparative Rate Statistics Report*, available online at http://www.floridapsc.com/Publications/Reports#.

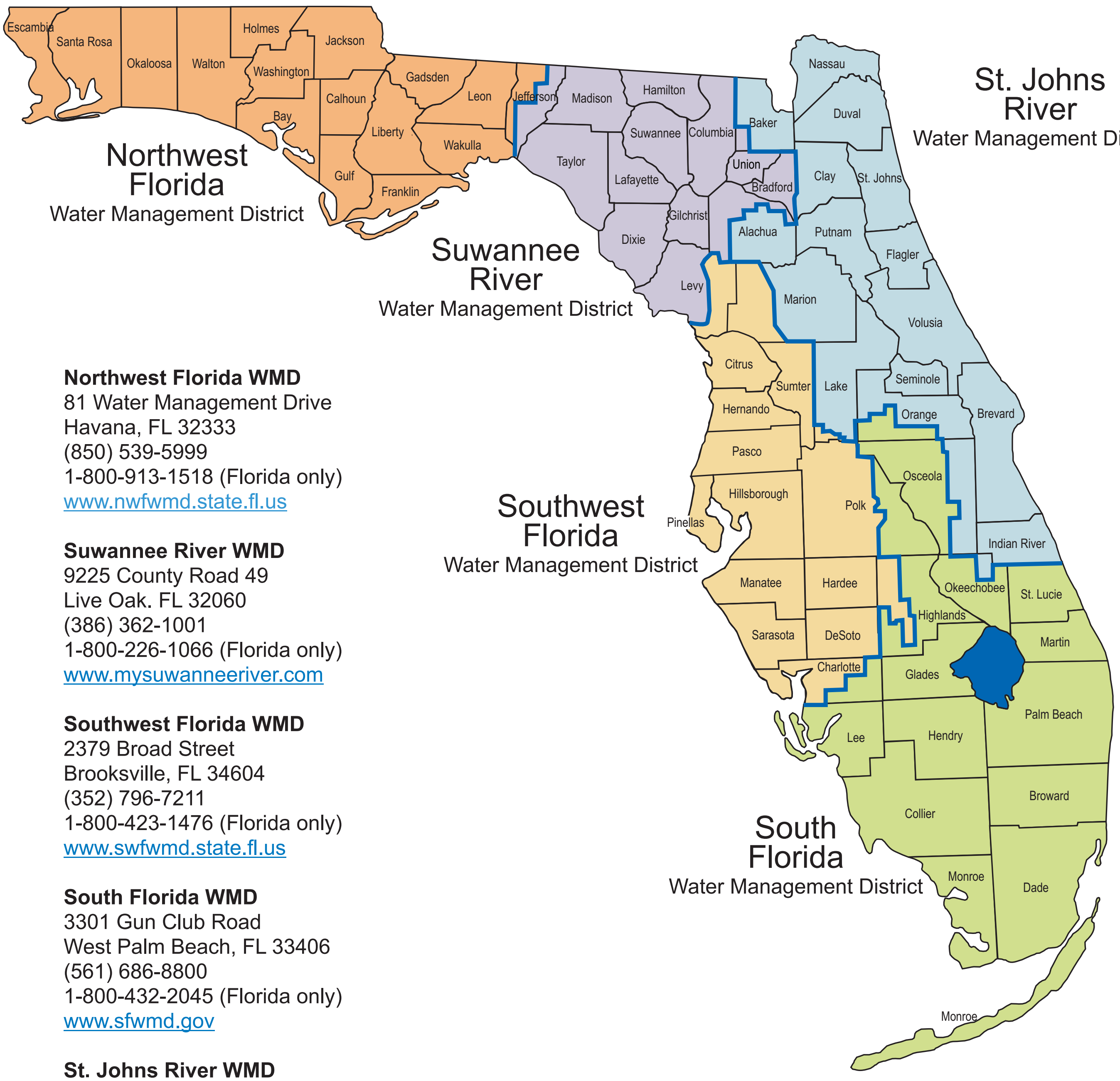
Source: FPSC Staff

Water & Wastewater Jurisdictional Counties (37)



Source:
Florida Public Service Commission Map
http://www.floridapsc.com/Files/PDF/Publications/Reports/Waterandwastewater/wawmap.pdf

Florida's Water Management Districts (5)



Northwest Florida WMD
81 Water Management Drive
Havana, FL 32333
(850) 539-5999
1-800-913-1518 (Florida only)
www.nwfwmd.state.fl.us

Suwannee River WMD
9225 County Road 49
Live Oak. FL 32060
(386) 362-1001
1-800-226-1066 (Florida only)
www.mysuwanneeriver.com

Southwest Florida WMD
2379 Broad Street
Brooksville, FL 34604
(352) 796-7211
1-800-423-1476 (Florida only)
www.swfwmd.state.fl.us

South Florida WMD
3301 Gun Club Road
West Palm Beach, FL 33406
(561) 686-8800
1-800-432-2045 (Florida only)
www.sfwmd.gov

St. Johns River WMD
4049 Reid Street
Palatka, FL 32177
(386) 329-4500
1-800-451-7106 (Florida only)
www.sjrwmd.com

Source: Florida Department of Environmental Protection, www.dep.state.fl.us/secretary/watman/