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June 19, 2017

-VIA ELECTRONIC DELIVERY –

Ms. Carlotta Stauffer, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 170097-EI – FPL's Petition for Approval of a New Depreciation Class and Rate for Energy Storage Equipment

Dear Ms. Stauffer:

Attached please find Florida Power and Light Company's Responses to Staff's First Data Request and Document Request.

Should you have any questions or concerns, please do not hesitate to contact my office at 561-304-5639.

Sincerely,

s/ John T. Butler
John T. Butler

Enclosures

QUESTION:
Please generally describe the type(s) of batteries contemplated and/or planned for use in effectuating Florida Power & Light's (FPL) 50 MW Battery Storage Pilot Program (Battery Storage Pilot). Please also note the function (i.e. production, transmission, distribution) if dissimilar assets will be used in each depreciable plant category.

RESPONSE:
FPL is still evaluating the most beneficial way to install batteries for purposes of the 50 MW Battery Storage Pilot Program. Once specific applications are finalized, the most appropriate battery type will be selected. Our present focus is on lithium ion batteries, which are the most flexible and mature battery technology currently in use for utility applications.

The choice of depreciable plant function will depend on the intended usage of the battery storage asset. For instance, if the battery is used for peak shaving, then it will be classified as production whereas a battery used for frequency response will be classified as transmission plant. Some batteries will have uses across multiple functions and will be allocated based on its intended uses. Refer to the response to Staff's First Data Request No. 11 for further information on the allocation approach.

QUESTION:
How many batteries by type does FPL intend to install in order to achieve the full 50 MW of battery storage?

RESPONSE:
FPL is still evaluating the most beneficial way to install batteries for purposes of the 50 MW Battery Storage Pilot Program. Once specific applications are finalized, the most appropriate battery type will be selected. It is expected that many different applications will be explored, resulting in a mix of battery sizes and types to fully implement the program.

QUESTION:
Has the Company begun installing any batteries and/or energy storage-associated equipment? If so, please identify the types of assets installed, dates of installation, number of MWs, and installation locations.

RESPONSE:
To date, FPL has not yet begun to install any batteries and/or energy storage-associated equipment associated with the implementation of its 50 MW battery storage pilot program, as provided in the Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-16-0560-AS-EI (Docket No. 160021-EI). However, in 2016 and early 2017, FPL did initiate and complete six smaller battery storage project installations (three residential/three commercial). The information requested for these six battery storage projects is provided below:

Project Name	**Type of Assets Installed**	**Install Date**	**Power/Energy**	**Location of Installation**
	Residential			
Community Storage 1	Kokam Batteries / S&C Inverter	May-16	25 kW / 50 kWh	Palm Beach
Community Storage 2	Kokam Batteries / S&C Inverter	Jan-17	25 kW / 50 kWh	Broward
Community Storage 3	Kokam Batteries / S&C Inverter	Jan-17	25 kW / 50 kWh	Miami-Dade
	Commercial			
Southwest Battery	BMW Batteries / Princeton Inverter	Aug-16	1.5 MW / 4 MWh	Miami-Dade
Florida Bay Battery	LG Chem Batteries / Dynapower Inverter	Dec-16	4.5 MW / 1.5 MWh	Monroe
Sony Tennis Battery	Exide Batteries / S&C UPS	Feb-17	750 kW / 12.5 kWh	Miami-Dade

QUESTION:
Please identify any currently scheduled installations of battery and/or energy storageassociated equipment.

RESPONSE:
FPL is still evaluating the most beneficial way to install batteries for purposes of the 50 MW Battery Storage Pilot Program. No specific projects have been approved by FPL's management to date, but the type of projects currently being evaluated under the Pilot include installations at various universal-scale solar sites. These installations could involve evaluation of the integration of Solar + Battery to better align the solar output with FPL's system peak. We are also considering a project in Miami at an existing FPL substation property (or similar site) designed to determine whether batteries can help mitigate the need to increase distribution infrastructure in dense urban environments when new loads come online.

QUESTION:

Is FPL currently recording any plant depreciation associated with its Battery Storage Pilot?

a. If the response to Request No. 5 is affirmative, is the company requesting any plant in service and accumulated depreciation transfers be performed as part of this docket?

b. If the response to Request No. 5(a.) is affirmative, please specify: amounts to be transferred; accounts in which the property/balances are currently being depreciated; and accounts to which the property/balances are being transferred to.

RESPONSE:

No, as of the date of this response, FPL has not installed any assets associated with the Battery Storage Pilot. That being said, FPL did install $9.5 million and $1.4 million in energy storage assets in 2016 and 2017, respectively, that are currently recorded in Account 362 – Station Equipment. These assets (Account 362 – Station Equipment) are being depreciated at an annual rate of 2.6% per the depreciation rates approved in FPL's 2016 rate case settlement (Order No. PSC-16-0560-AS-EI, Docket No. 160021-EI). FPL will transfer the plant in service and related accumulated depreciation of those energy storage assets to FERC Account 348 Energy Storage Equipment – Production or FERC Account 351 Energy Storage Equipment – Transmission or FERC Account 363 Energy Storage Equipment – Distribution, as appropriate depending on the use of the asset, upon receiving Commission approval for setting up these FERC accounts and the proposed average useful service life and net salvage values.

QUESTION:
Has FPL projected a date or timeframe when full implementation of the 50 MW Battery Storage Pilot will be achieved? If so, please specify the date or timeframe.

RESPONSE:
No. FPL is still evaluating the most beneficial way to install batteries for purposes of the 50 MW Battery Storage Pilot Program. Once specific applications are finalized, detailed project schedules will be able to be developed focusing on specific project permitting, procurement and design requirements. FPL plans to install the majority of the capacity over the next 18 months.

QUESTION:
Has FPL estimated the total capital cost associated with the full 50 MW of battery storage? If so, please specify.

RESPONSE:
FPL is still evaluating the most beneficial way to install batteries for purposes of the 50 MW Battery Storage Pilot Program. The location, applications and sizing of batteries will have an impact on costs. Currently, FPL is working towards defining projects in sufficient detail to estimate their costs. As specified in the 2016 Settlement Agreement, FPL intends to design projects that will allow it to stay within an average cost for the Pilot Program that does not exceed $2,300/kWAC.

QUESTION:
Is the Company aware of any other United States electric utility that has received regulatory approval for average service life and net salvage values for the purposes of depreciating energy storage equipment similar to the type(s) FPL will deploy? Is so, please identify the utility or utilities and specify the approved service life and net salvage values.

RESPONSE:
Yes. FPL is aware of the following utilities receiving regulatory approval for the average service life and net salvage values for energy storage assets:

1. Consolidated Edison of New York (ConEd) entered into a joint proposal and stipulation in Case No. 16-E-0060 approved by the New York Public Service Commission on January 25, 2017, which authorized an average service life of either 10 years or 15 years (depending on the project) and 0% net salvage for energy storage assets.

2. Pacific Gas & Electric (PG&E) received a decision (Decision 17-05-013) from the California Public Utility Commission on May 19, 2017, which authorized an average service life of 15 years and 0% net salvage for energy storage assets.

In addition, FPL notes that: 1) Southern California Edison (SCE) filed a depreciation study in Docket No. A.16-09 dated September 1, 2016 requesting an average service life of 10 years and 0% net salvage value for energy storage assets and 2) Puget Sound Energy filed a depreciation study in Docket No. UE-170033 dated January 13, 2017 requesting an average service life of 20 years and 0% net salvage value for energy storage assets. Both of these dockets are pending approval from their respective commissions.

FPL notes that there is diversity in practice in the industry with respect to the average useful service life ranging from 10 to 20 years for battery storage assets. FPL consulted its engineering subject matter experts and original equipment manufacturers for energy storage assets who indicated that a ten (10) year estimated useful life and 0% net salvage is reasonable at this time given the newness of the technology, recharge cycle time and lack of available retirement and salvage data across the industry. FPL plans to revisit the estimated useful life and salvage % for the battery storage asset in the future once more data becomes available.

QUESTION:
Please refer to paragraph (5) of FPL's Petition for Approval of a New Depreciation Class and Rate for Energy Storage Equipment (Petition). Please elaborate on how battery/energy storage may "enhance" service for large commercial and industrial customers, small retail customers, and or large retail customers.

RESPONSE:
The language referenced from Paragraph 5 of the Petition is taken directly from Paragraph 18 of FPL’s 2016 rate case settlement agreement, which authorizes and directs FPL to pursue the 50 MW Battery Storage Pilot Program. FPL is still evaluating the most beneficial way to install batteries for purposes of the Pilot Program. Initially, applications are being considered that will improve the integration of intermittent energy sources (i.e., solar) on both the transmission and distribution level, provide backup power during a grid outage, and/or provide support for grid voltage and/or frequency. FPL considers all of the potential benefits to be enhancements for our customers. In addition, FPL contemplates the installation of a few customer-sited batteries, which would improve power quality and serve as backup power.

Please note that, while the 50 MW Battery Storage Pilot Program specifically addresses battery storage systems, the proposed new depreciation accounts and rates also would apply to other forms of energy storage (e.g., thermal storage, compressed air, flow batteries, and molten storage), which FPL may investigate in the future.

QUESTION:
Please refer to paragraph (5) of FPL's Petition. Please list all known items which constitute "necessary equipment to connect such batteries to FPL's electric system."

RESPONSE:
Generally, FPL is considering deploying capacity both on the supply-side and demand-side of the system. As a result, the techniques and equipment needed to connect the batteries to FPL's electric system will vary. On supply-side interconnections, the battery could require any or all of the equipment outlined to be safely integrated into the FPL system. This could include but is not limited to: fuses, disconnect switches, utility poles, conduit and electrical wiring, conductors, breakers or switchgear, associated protection and control equipment, primary and backup power supply, use of control house space, metering, communications interface, SCADA controls and integration to operations systems, inverters, enclosures and associated components, safety equipment, cooling systems and spare parts.

On the demand-side, the standard interconnection method would be to an existing or new electrical panel or sub-panel, transformers, disconnect switch, conduit and electrical wiring, communications interface, metering, SCADA controls and integration to operations systems, inverters, enclosures and associated components, safety equipment, cooling systems and spare parts and necessary protection and controls equipment.

QUESTION:
Please refer to paragraph (6) of FPL' s Petition. Please provide a hypothetical accounting example of how FPL would "allocate a single asset to multiple functions."

RESPONSE:
FPL plans to allocate a single battery storage asset into multiple functions based on its planned usage of the battery storage assets at the inception of a project. FPL will not revise this initial allocation of the battery storage assets unless the actual usage differs significantly from the planned usage (e.g., greater than 25%). FPL believes that the year-over-year usage of the battery storage assets might differ from initial allocation; however, the overall usage over the life of the project should generally fall in line with the initial allocation.

For example, FPL might install the battery storage assets at one of its solar sites where FPL plans to use the installed battery storage assets primarily for peak shaving (i.e., charging batteries at non-peak times and discharging at peak times) and on occasion for frequency response during a system event. Peak shaving would be considered a generation function and frequency support would be considered a transmission function. If FPL concludes that it would use the battery storage assets 90% of the times for peak saving and 10% of the times for frequency regulation then such allocation would be applied to the costs of the battery storage assets at the inception of such project.

QUESTION:

Please refer to paragraph (6) of FPL's Petition. According to the Company: "FPL consulted with its engineering subject matter experts, original equipment manufactures for energy storage equipment and benchmarked with industry peers to conclude that a (10) year estimated useful life and net salvage of 0% is reasonable and appropriate."

a. Please identify the "subject matter experts" being referenced to in this passage.

b. Please identify the "original equipment manufacturers" being referenced to in this passage.

c. Concerning Request l 2(b.), will the batteries/energy storage equipment carry a warranty when purchased from the manufacturers? If so, please specify or approximate the typical warranty period.

d. Please identify the "industry peers" being referenced to in this passage.

RESPONSE:

a. The subject matter experts being referenced are engineers from FPL who have a detailed knowledge of energy storage assets and its various uses.

b. The original equipment manufacturer being referenced in paragraph (6) is LG Chem.

c. Yes, the batteries typically include a warranty of 2 to 3 years.

d. Refer to FPL’s response to Staff’s First Data Request No. 8.

QUESTION:
Please file with the Florida Public Service Commission (PSC) any documents the Company utilized in developing its proposed 10-year average service life and zero percent net salvage depreciation parameter request.

RESPONSE:
Responsive documents are attached. Please note that the references to depreciation parameters can be found as follows:

1. Consolidated Edison Joint Proposal – see Appendix 11, page 2 of 5 for Account 363;
2. Southern California Edison Depreciation Study – see page 56 for proposed useful life and page 61 for proposed net salvage; and
3. FERC Order No. 784 – see page 116 for discussion of the useful lives suggested by EEI of 10 to 15 years.

Consolidated Edison Company of New York, Inc.
Cases 16-E-0060 and 16-G-0061

Index of Appendices

Appendix 1 -- Electric Revenue Requirement

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2017
$ 000's

	Rate Year 1 Forecast	Rate Change	Rate Year 1 With Rate Change
Operating revenues			
Sales revenues	$ 7,476,999	$ 242,330	$ 7,719,329
Other revenues	305,241	1,042	306,283
Total operating revenues	7,782,240	243,372	8,025,612
Operating expense			
Fuel & purchased power costs	1,655,200	-	1,655,200
Operations & maintenance expenses	2,091,923	1,866	2,093,789
Depreciation	917,400	-	917,400
Taxes other than income taxes	1,540,137	6,179	1,546,316
Gain from disposition of utility plant	-	-	-
Total operating expenses	6,204,659	8,045	6,212,705
Operating income before income taxes	1,577,581	235,327	1,812,907
New York State income taxes	56,877	15,296	72,174
Federal income tax	373,755	77,011	450,766
Utility operating income	$ 1,146,948	$ 143,020	$ 1,289,968
Rate Base	$ 18,902,151		$ 18,902,151
Rate of Return	6.07%		6.82%

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2018
$ 000's

Operating revenues	Rate Year 1 Forecast	Rate Year 2 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 2 With Rate Change
Sales revenues	$ 7,719,329	$ 45,817	$ 155,315	$ 7,920,461
Other revenues	306,283	(336)	668	306,615
Total operating revenues	8,025,612	45,481	155,983	8,227,076
Operating expense				
Fuel & purchased power costs	1,655,200	(14,074)	-	1,641,126
Operations & maintenance expenses	2,093,789	26,296	1,196	2,121,281
Depreciation	917,400	48,966	-	966,365
Taxes other than income taxes	1,546,316	71,343	3,961	1,621,620
Gain from disposition of utility plant	-	-	-	-
Total operating expenses	6,212,705	132,531	5,156	6,350,392
Operating income before income taxes	1,812,907	(87,050)	150,826	1,876,684
New York State income taxes	72,174	(6,764)	9,804	75,213
Federal income tax	450,766	(26,501)	49,358	473,623
Utility operating income	$ 1,289,968	$ (53,785)	$ 91,665	$ 1,327,847
Rate Base	$ 18,902,151	$ 627,392		$ 19,529,543
Rate of Return	6.82%			6.80%

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2019
$ 000's

Operating revenues	Rate Year 2 Forecast	Rate Year 3 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 3 With Rate Change
Sales revenues	7,920,461	(24,841)	155,206	8,050,826
Other revenues	306,615	(12,090)	667	295,193
Total operating revenues	8,227,076	(36,931)	155,873	8,346,019
Operating expense				
Fuel & purchased power costs	1,641,126	(56,218)		1,584,908
Operations & maintenance expenses	2,121,281	(26,463)	1,195	2,096,014
Depreciation	966,365	57,415		1,023,780
Taxes other than income taxes	1,621,620	75,140	3,958	1,700,718
Gain from disposition of utility plant	-	-	-	-
Total operating expenses	6,350,392	49,874	5,153	6,405,419
Operating income before income taxes	1,876,684	(86,805)	150,721	1,940,599
New York State income taxes	75,213	(5,955)	9,797	79,056
Federal income tax	473,623	(25,699)	49,323	497,247
Utility operating income	1,327,847	(55,151)	91,600	1,364,296
Rate Base	$ 19,529,543	747,136		$ 20,276,680
Rate of Return	6.80%			6.73%

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Average Electric Rate Base
For The Twelve Months Ending December 31, 2017 and December 31, 2018
$ 000's

Utility plant:	Rate Year 1	Rate Year 2 Changes	Rate Year 2
Average Book Cost of Plant	$ 28,622,355	$ 1,446,810	$ 30,069,165
Non-Interest Bearing CWIP	792,364	(37,296)	755,068
Hudson Avenue	76,400	(3,900)	72,500
Average Accumulated Depreciation	(6,697,586)	(486,224)	(7,183,810)
Net utility plant	22,793,533	919,390	23,712,923
Rate base additions:			
Working Capital	832,165	20,524	852,690
Unamortized Preferred Stock Expense	19,048	(771)	18,277
Unamortized Debt Discount/Premium/Expense	115,797	1,268	117,065
Customer Advances for Construction	(4,020)	(84)	(4,104)
CATV Pole Attachment	(1,089)	-	(1,089)
Amounts Billed in Advance of Construction	(5,966)	(125)	(6,091)
Preliminary Survey & Investigation Costs	2,630	-	2,630
Rate base additions	958,565	20,812	979,378
Rate base deductions:			
Excess Rate Base Over Capitalization	(31,197)	-	(31,197)
Pension/OPEB Reduction	(141,980)	-	(141,980)
Former Employees/Contractor Proceeding	(21,087)	786	(20,301)
Rate base deductions	(194,264)	786	(193,478)
Regulatory deferrals			
Electric Regulatory Deferrals	29,589	58,755	88,344
Unbilled Revenues	91,000	-	91,000
Deferred Fuel (Net of Tax)	59,270	-	59,270
MTA Surtax- Net of Income Taxes	9,589	-	9,589
ERRP Maintenance Reserve	12,412	-	12,412
Brownfield State Tax Credits	(1,271)	-	(1,271)
Total Regulatory Deferrals	200,588	58,755	259,344
Accumulated deferred income taxes			
Hudson Avenue	(29,436)	-	(29,436)
Excess Deferred FIT	(22,047)	3,755	(18,292)
Accumulated Deferred Federal Income Taxes	(4,369,226)	(346,175)	(4,715,401)
Accumulated Deferred State Income Taxes	($435,564)	($29,931)	(465,495)
Accumulated deferred income taxes	(4,856,272)	(372,351)	(5,228,623)
Total Rate Base	$ 18,902,151	$ 627,392	$ 19,529,543

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Average Electric Rate Base
For The Twelve Months Ending December 31, 2019
$ 000's

	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Utility plant:			
Average Book Cost of Plant	$ 30,069,165	$ 1,573,823	$ 31,642,988
Non-Interest Bearing CWIP	755,068	34,368	789,436
Hudson Avenue	72,500	(3,800)	68,700
Average Accumulated Depreciation	(7,183,810)	(578,875)	(7,762,685)
Net utility plant	23,712,923	1,025,516	24,738,439
Rate base additions:			
Working Capital	852,690	12,056	864,745
Unamortized Preferred Stock Expense	18,277	(771)	17,506
Unamortized Debt Discount/Premium/Expense	117,065	(1,977)	115,088
Customer Advances for Construction	(4,104)	(86)	(4,190)
MTA Surtax - Net of Income Taxes	(1,089)		(1,089)
Accrual for Unbilled Revenues	(6,091)	(128)	(6,219)
Preliminary Survey & Investigation Costs	2,630		2,630
Rate base additions	979,378	9,094	988,471
Rate base deductions:			
Excess Rate Base Over Capitalization	(31,197)	-	(31,197)
Pension/OPEB Reduction	(141,980)	-	(141,980)
Former Employees/Contractor Proceeding	(20,301)	786	(19,515)
Rate base deductions	(193,478)	786	(192,692)
Regulatory deferrals			
Electric Regulatory Deferrals	88,344	89,578	177,922
Unbilled Revenues	91,000	-	91,000
Deferred Fuel (Net of Tax)	59,270	-	59,270
MTA Surtax- Net of Income Taxes	9,589	-	9,589
ERRP Maintenance Reserve	12,412	-	12,412
Brownfield State Tax Credits	(1,271)	-	(1,271)
Total Regulatory Deferrals	259,344	89,578	348,922
Accumulated deferred income taxes			
Hudson Avenue	(29,436)	-	(29,436)
Excess Deferred FIT	(18,292)	3,504	(14,788)
Accumulated Deferred Federal Income Taxes	(4,715,401)	(347,540)	(5,062,941)
Accumulated Deferred State Income Taxes	(465,495)	($33,801)	(499,296)
Accumulated deferred income taxes	(5,228,623)	(377,837)	(5,606,460)
Total Rate Base	$ 19,529,543	$ 747,136	$ 20,276,680

Consolidated Edison Company of New York, Inc.
Electric Case 16-E-0060
Average Capital Structure & Cost of Money
For the Twelve Months Ending December 31, 2017, December 31, 2018 and December 31, 2019

RY 1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.55%	4.93%	2.49%	2.49%
Customer deposits	1.45%	0.85%	0.01%	0.01%
Subtotal	52.00%		2.50%	2.50%
Common Equity	48.00%	9.00%	4.32%	7.11%
Total	100.00%		6.82%	9.61%

RY 2

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.55%	4.88%	2.47%	2.47%
Customer deposits	1.45%	0.85%	0.012%	0.01%
Subtotal	52.00%		2.48%	2.48%
Common Equity	48.00%	9.00%	4.32%	7.11%
Total	100.00%		6.80%	9.59%

RY 3

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.55%	4.74%	2.40%	2.40%
Customer deposits	1.45%	0.85%	0.01%	0.01%
Subtotal	52.00%		2.41%	2.41%
Common Equity	48.00%	9.00%	4.32%	7.11%
Total	100.00%		6.73%	9.52%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
LONG TERM DEBT
Forecast - Rate Year Ended December 31, 2017

CECONY			Issue Date	Maturity Date	a Amount Outstanding	b Original Issue Amount	c Premium or Discount	d Expense of Issuance	e = b + c + d Net Proceeds	f = g / a Cost of Debt	g Effective Annual Cost
Debentures:											
	2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	(1,662,326)	172,315,674	5.93%	10,370,728
	2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	(1,866,135)	197,797,865	5.14%	10,273,404
	2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	(1,864,406)	197,597,594	5.74%	11,480,080
	2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	(3,541,534)	345,264,966	5.35%	18,707,834
	2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	(1,142,914)	123,125,836	5.30%	6,624,972
	2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	(3,616,500)	396,323,500	5.88%	23,522,550
	2006 Series B	6.2050%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	(3,669,000)	395,575,000	6.24%	24,967,500
	2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	(2,262,500)	247,025,000	5.74%	14,349,167
	2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	(4,751,250)	517,324,500	6.35%	33,330,850
	2008 Series A	5.8500%	4/1/08	04/01/18	600,000,000	600,000,000	(264,000)	(4,099,750)	595,636,250	5.92%	35,536,375
	2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	(5,449,750)	592,792,250	6.79%	40,740,258
	2008 Series C	7.1250%	12/2/08	12/01/18	600,000,000	600,000,000	(2,148,000)	(3,962,633)	593,889,367	7.23%	43,361,063
	2009 Series B	6.6500%	3/23/09	04/01/19	475,000,000	475,000,000	(693,500)	(3,284,067)	471,022,433	6.73%	31,985,257
	2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	(5,673,813)	592,058,187	5.54%	33,264,727
	2010 Series A	4.4500%	6/2/10	05/01/20	350,000,000	350,000,000	(759,500)	(2,518,935)	346,721,565	4.54%	15,902,843
	2010 Series B	5.7000%	6/2/10	05/01/40	350,000,000	350,000,000	(1,701,000)	(3,306,369)	344,992,631	5.75%	20,116,912
	2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	(4,228,381)	394,347,619	4.25%	16,988,413
	2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	(6,866,027)	688,261,973	4.01%	28,041,268
	2014 Series A	4.4500%	3/6/14	03/15/44	850,000,000	850,000,000	(714,000)	(8,804,659)	840,481,341	4.49%	38,142,289
	2014 Series B	3.3000%	11/24/14	12/01/24	250,000,000	250,000,000	(867,500)	(2,042,196)	247,090,304	3.42%	8,540,970
	2014 Series C	4.6250%	11/24/14	12/01/54	750,000,000	750,000,000	(1,912,500)	(7,814,167)	740,273,333	4.66%	34,930,667
	2015 Series A	4.5000%	11/17/15	12/01/45	650,000,000	650,000,000	(650,000)	(6,662,500)	642,687,500	4.54%	29,493,750
	2016 Series A	3.8500%	6/1/16	06/01/46	550,000,000	550,000,000	(775,500)	(5,916,786)	543,307,714	3.89%	21,398,076
	2016 Series B	3.8200%	11/1/16	11/01/46	750,000,000	750,000,000	(2,460,000)	(7,687,500)	739,852,500	3.87%	28,988,250
*	**2017** Series A	4.2750%	3/1/17	03/01/47	395,833,333	475,000,000	(1,391,750)	(4,868,750)	468,739,500	4.32%	17,095,778
*	**2017** Series B	4.2750%	11/1/17	11/01/47	125,000,000	750,000,000	(2,197,500)	(7,687,500)	740,115,000	4.32%	5,398,667
					11,620,833,333	12,325,000,000	(35,130,250)	(115,250,347)	12,174,619,403	5.19%	603,552,648
Tax Exempt Debt Issue through New York State											
	1999 Series A	AUC	7/10/01	05/01/34	292,700,000	292,700,000	-	(4,577,677)	288,122,323	1.15%	3,351,839
	2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	(4,906,341)	219,693,659	1.73%	3,878,913
	2001 Series B	AUC	10/18/01	10/01/36	98,000,000	98,000,000	-	(1,169,324)	96,830,676	1.38%	1,349,562
	2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	(1,534,332)	96,790,668	1.23%	1,207,036
	2004 Series B1	AUC	1/22/04	05/01/32	127,225,000	127,225,000	-	(1,985,912)	125,239,088	1.22%	1,550,569
	2004 Series B2	AUC	1/22/04	10/01/35	19,750,000	19,750,000	-	(307,066)	19,442,934	1.03%	203,715
	2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	(1,834,951)	97,165,049	1.45%	1,431,510
	2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	(1,842,329)	124,457,671	1.52%	1,914,602
					1,085,900,000	1,085,900,000	-	(18,157,933)	1,067,742,067	1.37%	14,887,748
Subtotals					12,706,733,333	13,410,900,000	(35,130,250)	(133,408,280)	13,242,361,470	4.87%	618,440,395
Redemption of Preferred Stock											993,442
Unamortized Loss on Reacquired Debt Expense											6,965,014
Total CECONY					$ 12,706,733,333					**4.93%**	$ 626,398,851

Note:
* Debt outstanding balances and annual costs are prorated for the months outstanding during the period.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

LONG TERM DEBT

Forecast - Rate Year Ended December 31, 2018

CECONY			Issue Date	Maturity Date	a Amount Outstanding	b Original Issue Amount	c Premium or Discount	d Expense of Issuance	e = b + c + d Net Proceeds	f = g / a Cost of Debt	g Effective Annual Cost
Debentures:											
	2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	(1,662,326)	172,315,674	5.93%	10,370,728
	2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	(1,866,135)	197,797,865	5.14%	10,273,404
	2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	(1,864,406)	197,597,594	5.74%	11,480,080
	2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	(3,541,534)	345,264,966	5.35%	18,707,834
	2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	(1,142,914)	123,125,836	5.30%	6,624,972
	2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	(3,616,500)	396,323,500	5.88%	23,522,550
	2006 Series B	6.2050%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	(3,669,000)	395,575,000	6.24%	24,967,500
	2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	(2,262,500)	247,025,000	5.74%	14,349,167
	2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	(4,751,250)	517,324,500	6.35%	33,330,850
*	**2008** Series A	5.8500%	4/1/08	04/01/18	150,000,000	600,000,000	(264,000)	(4,099,750)	595,636,250	5.92%	8,884,094
	2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	(5,449,750)	592,792,250	6.79%	40,740,258
*	**2008** Series C	7.1250%	12/2/08	12/01/18	550,000,000	600,000,000	(2,148,000)	(3,962,633)	593,889,367	7.23%	39,747,641
	2009 Series B	6.6500%	3/23/09	04/01/19	475,000,000	475,000,000	(693,500)	(3,284,067)	471,022,433	6.73%	31,985,257
	2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	(5,673,813)	592,058,187	5.54%	33,264,727
	2010 Series A	4.4500%	6/2/10	05/01/20	350,000,000	350,000,000	(759,500)	(2,518,935)	346,721,565	4.54%	15,902,843
	2010 Series B	5.7000%	6/2/10	05/01/40	350,000,000	350,000,000	(1,701,000)	(3,306,369)	344,992,631	5.75%	20,116,912
	2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	(4,228,381)	394,347,619	4.25%	16,988,413
	2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	(6,866,027)	688,261,973	4.01%	28,041,268
	2014 Series A	4.4500%	3/6/14	03/15/44	850,000,000	850,000,000	(714,000)	(8,804,659)	840,481,341	4.49%	38,142,289
	2014 Series B	3.3000%	11/24/14	12/01/24	250,000,000	250,000,000	(867,500)	(2,042,196)	247,090,304	3.42%	8,540,970
	2014 Series C	4.6250%	11/24/14	12/01/54	750,000,000	750,000,000	(1,912,500)	(7,814,167)	740,273,333	4.66%	34,930,667
	2015 Series A	4.5000%	11/17/15	12/01/45	650,000,000	650,000,000	(650,000)	(6,662,500)	642,687,500	4.54%	29,493,750
	2016 Series A	3.8500%	6/1/16	06/01/46	550,000,000	550,000,000	(1,804,000)	(5,637,500)	542,558,500	3.90%	21,423,050
	2016 Series B	3.8200%	11/1/16	11/01/46	750,000,000	750,000,000	(2,460,000)	(7,687,500)	739,852,500	3.87%	28,988,250
	2017 Series A	4.2750%	3/1/17	03/01/47	475,000,000	475,000,000	(1,391,750)	(4,868,750)	468,739,500	4.32%	20,514,933
	2017 Series B	4.2750%	11/1/17	11/01/47	750,000,000	750,000,000	(2,197,500)	(7,687,500)	740,115,000	4.32%	32,392,000
*	**2018** Series A	4.5600%	3/1/18	03/01/48	395,833,333	475,000,000	(669,750)	(4,868,750)	469,461,500	4.60%	18,203,847
*	**2018** Series B	4.5600%	11/1/18	11/01/48	166,666,667	1,000,000,000	(1,410,000)	(10,250,000)	988,340,000	4.60%	7,664,778
					12,387,500,000	13,800,000,000	(38,238,500)	(130,089,811)	13,631,671,689	5.08%	629,593,032
Tax Exempt Debt Issue through New York State											
	1999 Series A	AUC	7/10/01	05/01/34	292,700,000	292,700,000	-	(4,577,677)	288,122,323	1.74%	5,079,532
	2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	(4,906,341)	219,693,659	2.08%	4,665,013
	2001 Series B	AUC	10/18/01	10/01/36	98,000,000	98,000,000	-	(1,169,324)	96,830,676	1.85%	1,810,162
	2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	(1,534,332)	96,790,668	1.82%	1,792,070
	2004 Series B1	AUC	1/22/04	05/01/32	127,225,000	127,225,000	-	(1,985,912)	125,239,088	1.83%	2,333,003
	2004 Series B2	AUC	1/22/04	10/01/35	19,750,000	19,750,000	-	(307,066)	19,442,934	1.65%	325,178
	2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	(1,834,951)	97,165,049	1.80%	1,778,010
	2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	(1,842,329)	124,457,671	1.88%	2,369,282
					1,085,900,000	1,085,900,000	-	(18,157,933)	1,067,742,067	1.86%	20,152,251
Subtotals					13,473,400,000	14,885,900,000	(38,238,500)	(148,247,744)	14,699,413,756	4.82%	649,745,283
Redemption of Preferred Stock											993,442
Unamortized Loss on Reacquired Debt Expense											6,965,014
Total CECONY					$ 13,473,400,000					**4.88%**	$ 657,703,739

Note:

* Debt outstanding balances and annual costs are prorated for the months outstanding during the period.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
LONG TERM DEBT
Forecast - Rate Year Ended December 31, 2019

	CECONY		Issue Date	Maturity Date	a Amount Outstanding	b Original Issue Amount	c Premium or Discount	d Expense of Issuance	e = b + c + d Net Proceeds	f = g / a Cost of Debt	g Effective Annual Cost
	Debentures:										
	2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	(1,662,326)	172,315,674	5.93%	10,370,728
	2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	(1,866,135)	197,797,865	5.14%	10,273,404
	2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	(1,864,406)	197,597,594	5.74%	11,480,080
	2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	(3,541,534)	345,264,966	5.35%	18,707,834
	2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	(1,142,914)	123,125,836	5.30%	6,624,972
	2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	(3,616,500)	396,323,500	5.88%	23,522,550
	2006 Series B	6.2050%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	(3,669,000)	395,575,000	6.24%	24,967,500
	2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	(2,262,500)	247,025,000	5.74%	14,349,167
	2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	(4,751,250)	517,324,500	6.35%	33,330,850
	2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	(5,449,750)	592,792,250	6.79%	40,740,258
*	**2009** Series B	6.6500%	3/23/09	04/01/19	118,750,000	475,000,000	(693,500)	(3,284,067)	471,022,433	6.73%	7,996,314
	2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	(5,673,813)	592,058,187	5.54%	33,264,727
	2010 Series A	4.4500%	6/2/10	05/01/20	350,000,000	350,000,000	(759,500)	(2,518,935)	346,721,565	4.54%	15,902,843
	2010 Series B	5.7000%	6/2/10	05/01/40	350,000,000	350,000,000	(1,701,000)	(3,306,369)	344,992,631	5.75%	20,116,912
	2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	(4,228,381)	394,347,619	4.25%	16,988,413
	2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	(6,866,027)	688,261,973	4.01%	28,041,268
	2014 Series A	4.4500%	3/6/14	03/15/44	850,000,000	850,000,000	(714,000)	(8,804,659)	840,481,341	4.49%	38,142,289
	2014 Series B	3.3000%	11/24/14	12/01/24	250,000,000	250,000,000	(867,500)	(2,042,196)	247,090,304	3.42%	8,540,970
	2014 Series C	4.6250%	11/24/14	12/01/54	750,000,000	750,000,000	(1,912,500)	(7,814,167)	740,273,333	4.66%	34,930,667
	2015 Series A	4.5000%	11/17/15	12/01/45	650,000,000	650,000,000	(650,000)	(6,662,500)	642,687,500	4.54%	29,493,750
	2016 Series A	3.8500%	6/1/16	06/01/46	550,000,000	550,000,000	(1,804,000)	(5,637,500)	542,558,500	3.90%	21,423,050
	2016 Series B	3.8200%	11/1/16	11/01/46	750,000,000	750,000,000	(2,460,000)	(7,687,500)	739,852,500	3.87%	28,988,250
	2017 Series A	4.2750%	3/1/17	03/01/47	475,000,000	475,000,000	(1,391,750)	(4,868,750)	468,739,500	4.32%	20,514,933
	2017 Series B	4.2750%	11/1/17	11/01/47	750,000,000	750,000,000	(2,197,500)	(7,687,500)	740,115,000	4.32%	32,392,000
	2018 Series A	4.5600%	3/1/18	03/01/48	475,000,000	475,000,000	(669,750)	(4,868,750)	469,461,500	4.60%	21,844,617
	2018 Series B	4.5600%	11/1/18	11/01/48	1,000,000,000	1,000,000,000	(1,410,000)	(10,250,000)	988,340,000	4.60%	45,988,667
*	**2019** Series A	4.7100%	3/1/19	03/01/49	791,666,667	950,000,000	(1,311,000)	(9,737,500)	938,951,500	4.75%	37,594,403
					13,035,416,667	13,550,000,000	(37,137,500)	(131,764,928)	13,381,097,572	4.88%	636,531,415
	Tax Exempt Debt Issue through New York State										
	1999 Series A	AUC	7/10/01	05/01/34	292,700,000	292,700,000	-	(4,577,677)	288,122,323	2.33%	6,821,097
	2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	(4,906,341)	219,693,659	2.43%	5,451,113
	2001 Series B	AUC	10/18/01	10/01/36	98,000,000	98,000,000	-	(1,169,324)	96,830,676	2.32%	2,270,762
	2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	(1,534,332)	96,790,668	2.42%	2,377,103
	2004 Series B1	AUC	1/22/04	05/01/32	127,225,000	127,225,000	-	(1,985,912)	125,239,088	2.45%	3,115,437
	2004 Series B2	AUC	1/22/04	10/01/35	19,750,000	19,750,000	-	(307,066)	19,442,934	2.26%	446,640
	2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	(1,834,951)	97,165,049	2.15%	2,124,510
	2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	(1,842,329)	124,457,671	2.24%	2,823,962
					1,085,900,000	1,085,900,000	0	(18,157,933)	1,067,742,067	2.34%	25,430,626
	Subtotals				14,121,316,667	14,635,900,000	(37,137,500)	(149,922,860)	14,448,839,640	4.69%	661,962,041
	Redemption of Preferred Stock										993,442
	Unamortized Loss on Reacquired Debt Expense										6,965,014
	Total CECONY				$ 14,121,316,667					**4.74%**	$ 669,920,497

Note:
* Debt outstanding balances and annual costs are prorated for the months outstanding during the period.

Consolidated Edison Company of New York, Inc.
Electric Case 16-E-0060
Calculation of Levelized Rate Increase
For the Twelve Months Ending December 31, 2017, December 31, 2018 and December 31, 2019
$ 000's

Rate Increase	Twelve Months Ending December 31, 2017	2018	2019	Cumulative Total
RY - 1	$ 242,330	$ 242,330	$ 242,330	$ 726,990
RY - 2		155,315	155,315	310,630
RY - 3			155,206	155,206
Total	$ 242,330	$ 397,645	$ 552,851	$ 1,192,826
Levelized rate increase without interest				
RY - 1	$ 198,804	$ 198,804	$ 198,804	$ 596,413
RY - 2		198,804	198,804	397,609
RY - 3			198,804	198,804
Total	$ 198,804	$ 397,609	$ 596,413	$ 1,192,826
Variation	$ 43,526	$ 36	$ (43,562)	$ -
Interest at 2.6%	$ 344	$ 688	$ 344	$ 1,376
Levelized rate increase with interest				
RY - 1	$ 199,034	$ 199,034	$ 199,034	$ 597,101
RY - 2		199,034	199,034	398,067
RY - 3			199,034	199,034
Total	$ 199,034	$ 398,067	$ 597,101	$ 1,194,202

Consolidated Edison Company of New York, Inc.
Electric Case 16-E-0060
Revenue Summary
For the Twelve Months Ending December 31, 2017
$ 000's

Base rate change in Joint Proposal in Case 16-E-0060 (including temporary credit)	$ 242,330
Base rate change approved by the Commission in Case 13-E-0030 effective January 1, 2017 through the expiration of the temporary credit	(47,776)
Base rate change in Joint Proposal in Case 16-E-0060 (excluding temporary credit)	$ 194,554

Appendix 2 -- Gas Revenue Requirement

Consolidated Edison Company of New York, Inc.
Case 16-G-0061
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2017
$ 000's

Operating revenues	Rate Year 1 Forecast	Rate Change	Rate Year 1 With Rate Change
Sales revenues	$ 1,655,490	$ 35,483	$ 1,690,973
Other revenues	74,820	124	74,944
Total operating revenues	1,730,310	35,607	1,765,917
Operating expense			
Fuel & purchased power costs	392,527	-	392,527
Operations & maintenance expenses	408,587	273	408,860
Depreciation	184,117	-	184,117
Taxes other than income taxes	299,261	1,228	300,489
Gain from disposition of utility plant	-	-	-
Total operating expenses	1,284,492	1,501	1,285,993
Operating income before income taxes	445,818	34,106	479,924
New York State income taxes	17,939	2,217	20,156
Federal income tax	118,268	11,161	129,429
Utility operating income	$ 309,611	$ 20,728	$ 330,339
Rate Base	$ 4,840,848		$ 4,840,848
Rate of Return	6.40%		6.82%

Consolidated Edison Company of New York, Inc.
Case 16-G-0061
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2018
$ 000's

Operating revenues	Rate Year 1 Forecast	Rate Year 2 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 2 With Rate Change
Sales revenues	$ 1,690,973	$ 38,701	$ 92,337	$ 1,822,011
Other revenues	74,944	(169)	322	75,098
Total operating revenues	1,765,917	38,532	92,659	1,897,109
Operating expense				
Fuel & purchased power costs	392,527	13,001	-	405,528
Operations & maintenance expenses	408,860	6,916	711	416,488
Depreciation	184,117	20,225	-	204,342
Taxes other than income taxes	300,489	30,810	3,195	334,493
Gain from disposition of utility plant	-	-	-	-
Total operating expenses	1,285,993	70,952	3,906	1,360,851
Operating income before income taxes	479,924	(32,420)	88,753	536,257
New York State income taxes	20,156	(2,980)	5,769	22,945
Federal income tax	129,429	(11,945)	29,045	146,528
Utility operating income	$ 330,339	$ (17,495)	$ 53,940	$ 366,784
Rate Base	$ 4,840,848	$ 553,837		$ 5,394,685
Rate of Return	6.82%			6.80%

Consolidated Edison Company of New York, Inc.
Case 16-G-0061
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2019
$ 000's

Operating revenues	Rate Year 2 Forecast	Rate Year 3 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 3 With Rate Change
Sales revenues	1,822,011	34,750	89,453	1,946,214
Other revenues	75,098	(524)	312	74,886
Total operating revenues	1,897,109	34,226	89,765	2,021,100
Operating expense				
Fuel & purchased power costs	405,528	12,813	-	418,341
Operations & maintenance expenses	416,488	(4,835)	689	412,342
Depreciation	204,342	21,424	-	225,766
Taxes other than income taxes	334,493	33,159	3,095	370,747
Gain from disposition of utility plant	-	-	-	-
Total operating expenses	1,360,851	62,561	3,784	1,427,196
Operating income before income taxes	536,257	(28,335)	85,981	593,904
New York State income taxes	22,945	(2,567)	5,589	25,966
Federal income tax	146,528	(10,745)	28,137	163,921
Utility operating income	366,784	(15,022)	52,255	404,017
Rate Base	$ 5,394,685	610,326		$ 6,005,011
Rate of Return	6.80%			6.73%

Consolidated Edison Company of New York, Inc.
Case 16-G-0061
Average Gas Rate Base
For The Twelve Months Ending December 31, 2017 and December 31, 2018
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2
Utility plant:			
Average Book Cost of Plant	$ 7,465,914	$ 837,023	$ 8,302,937
Non-Interest Bearing CWIP	286,330	(9,304)	277,026
Average Accumulated Depreciation	(1,580,437)	(113,898)	(1,694,335)
Net utility plant	6,171,807	713,821	6,885,628
Rate base additions:			
Working Capital	112,562	7,019	119,581
Gas Stored Underground - Non-Current	1,239	-	1,239
Unamortized Preferred Stock Expense	3,608	(146)	3,462
Unamortized Debt Discount/Premium/Expense	21,936	240	22,176
Customer Advances for Construction	(1,901)	(40)	(1,941)
MTA Surtax - Net of Income Taxes	2,764	-	2,764
Accrual for Unbilled Revenues	43,594	-	43,594
Preliminary Survey & Investigation Costs	650	-	650
Rate base additions	184,452	7,073	191,525
Rate base deductions:			
Excess Rate Base Over Capitalization	86,695	-	86,695
Pension/OPEB Reduction	(16,201)	-	(16,201)
Former Employees/Contractor Proceeding	(5,176)	193	(4,983)
Rate base deductions	65,318	193	65,511
Regulatory deferrals	(31,430)	20,496	(10,934)
Accumulated deferred income taxes			
Excess Deferred FIT	(8,583)	508	(8,075)
Accumulated Deferred Federal Income Taxes	(1,444,987)	(179,404)	(1,624,391)
Accumulated Deferred State Income Taxes	(95,729)	(8,850)	(104,579)
Accumulated deferred income taxes	(1,549,299)	(187,746)	(1,737,045)
Total Rate Base	$ 4,840,848	$ 553,837	$ 5,394,685

Consolidated Edison Company of New York, Inc.
Case 16-G-0061
Average Gas Rate Base
For The Twelve Months Ending December 31, 2019
$ 000's

Utility plant:	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Average Book Cost of Plant	$ 8,302,937	$ 873,555	$ 9,176,492
Non-Interest Bearing CWIP	277,026	27,448	304,474
Average Accumulated Depreciation	(1,694,335)	(141,929)	(1,836,264)
Net utility plant	6,885,628	759,074	7,644,702
Rate base additions:			
Working Capital	119,581	6,004	125,585
Gas Stored Underground - Non-Current	1,239	-	1,239
Unamortized Preferred Stock Expense	3,462	(146)	3,316
Unamortized Debt Discount/Premium/Expense	22,176	(375)	21,801
Customer Advances for Construction	(1,941)	(41)	(1,982)
MTA Surtax - Net of Income Taxes	2,764	-	2,764
Accrual for Unbilled Revenues	43,594	-	43,594
Preliminary Survey & Investigation Costs	650	-	650
Rate base additions	191,525	5,442	196,967
Rate base deductions:			
Excess Rate Base Over Capitalization	86,695	-	86,695
Pension/OPEB Reduction	(16,201)	-	(16,201)
Former Employees/Contractor Proceeding	(4,983)	192	(4,791)
Rate base deductions	65,511	192	65,703
Regulatory deferrals	(10,934)	19,809	8,875
Accumulated deferred income taxes			
Excess Deferred FIT	(8,075)	496	(7,579)
Accumulated Deferred Federal Income Taxes	(1,624,391)	(164,355)	(1,788,746)
Accumulated Deferred State Income Taxes	(104,579)	(10,332)	(114,911)
Accumulated deferred income taxes	(1,737,045)	(174,191)	(1,911,236)
Total Rate Base	$ 5,394,685	$ 610,326	$ 6,005,011

Consolidated Edison Company of New York, Inc.
Gas Case 16-G-0061
Average Capital Structure & Cost of Money
For the Twelve Months Ending December 31, 2017, December 31, 2018 and December 31, 2019

RY 1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.55%	4.93%	2.49%	2.49%
Customer deposits	1.45%	0.85%	0.01%	0.01%
Subtotal	52.00%		2.50%	2.50%
Common Equity	48.00%	9.00%	4.32%	7.11%
Total	100.00%		6.82%	9.61%

RY 2

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.55%	4.88%	2.47%	2.47%
Customer deposits	1.45%	0.85%	0.012%	0.01%
Subtotal	52.00%		2.48%	2.48%
Common Equity	48.00%	9.00%	4.32%	7.11%
Total	100.00%		6.80%	9.59%

RY 3

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.55%	4.74%	2.40%	2.40%
Customer deposits	1.45%	0.85%	0.01%	0.01%
Subtotal	52.00%		2.41%	2.41%
Common Equity	48.00%	9.00%	4.32%	7.11%
Total	100.00%		6.73%	9.52%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
LONG TERM DEBT
Forecast - Rate Year Ended December 31, 2017

CECONY			Issue Date	Maturity Date	a Amount Outstanding	b Original Issue Amount	c Premium or Discount	d Expense of Issuance	e = b + c + d Net Proceeds	f = g / a Cost of Debt	g Effective Annual Cost
Debentures:											
	2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	(1,662,326)	172,315,674	5.93%	10,370,728
	2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	(1,866,135)	197,797,865	5.14%	10,273,404
	2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	(1,864,406)	197,597,594	5.74%	11,480,080
	2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	(3,541,534)	345,264,966	5.35%	18,707,834
	2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	(1,142,914)	123,125,836	5.30%	6,624,972
	2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	(3,616,500)	396,323,500	5.88%	23,522,550
	2006 Series B	6.2050%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	(3,669,000)	395,575,000	6.24%	24,967,500
	2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	(2,262,500)	247,025,000	5.74%	14,349,167
	2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	(4,751,250)	517,324,500	6.35%	33,330,850
	2008 Series A	5.8500%	4/1/08	04/01/18	600,000,000	600,000,000	(264,000)	(4,099,750)	595,636,250	5.92%	35,536,375
	2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	(5,449,750)	592,792,250	6.79%	40,740,258
	2008 Series C	7.1250%	12/2/08	12/01/18	600,000,000	600,000,000	(2,148,000)	(3,962,633)	593,889,367	7.23%	43,361,063
	2009 Series B	6.6500%	3/23/09	04/01/19	475,000,000	475,000,000	(693,500)	(3,284,067)	471,022,433	6.73%	31,985,257
	2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	(5,673,813)	592,058,187	5.54%	33,264,727
	2010 Series A	4.4500%	6/2/10	05/01/20	350,000,000	350,000,000	(759,500)	(2,518,935)	346,721,565	4.54%	15,902,843
	2010 Series B	5.7000%	6/2/10	05/01/40	350,000,000	350,000,000	(1,701,000)	(3,306,369)	344,992,631	5.75%	20,116,912
	2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	(4,228,381)	394,347,619	4.25%	16,988,413
	2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	(6,866,027)	688,261,973	4.01%	28,041,268
	2014 Series A	4.4500%	3/6/14	03/15/44	850,000,000	850,000,000	(714,000)	(8,804,659)	840,481,341	4.49%	38,142,289
	2014 Series B	3.3000%	11/24/14	12/01/24	250,000,000	250,000,000	(867,500)	(2,042,196)	247,090,304	3.42%	8,540,970
	2014 Series C	4.6250%	11/24/14	12/01/54	750,000,000	750,000,000	(1,912,500)	(7,814,167)	740,273,333	4.66%	34,930,667
	2015 Series A	4.5000%	11/17/15	12/01/45	650,000,000	650,000,000	(650,000)	(6,662,500)	642,687,500	4.54%	29,493,750
	2016 Series A	3.8500%	6/1/16	06/01/46	550,000,000	550,000,000	(775,500)	(5,916,786)	543,307,714	3.89%	21,398,076
	2016 Series B	3.8200%	11/1/16	11/01/46	750,000,000	750,000,000	(2,460,000)	(7,687,500)	739,852,500	3.87%	28,988,250
*	**2017** Series A	4.2750%	3/1/17	03/01/47	395,833,333	475,000,000	(1,391,750)	(4,868,750)	468,739,500	4.32%	17,095,778
*	**2017** Series B	4.2750%	11/1/17	11/01/47	125,000,000	750,000,000	(2,197,500)	(7,687,500)	740,115,000	4.32%	5,398,667
					11,620,833,333	12,325,000,000	(35,130,250)	(115,250,347)	12,174,619,403	5.19%	603,552,648
Tax Exempt Debt Issue through New York State											
	1999 Series A	AUC	7/10/01	05/01/34	292,700,000	292,700,000	-	(4,577,677)	288,122,323	1.15%	3,351,839
	2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	(4,906,341)	219,693,659	1.73%	3,878,913
	2001 Series B	AUC	10/18/01	10/01/36	98,000,000	98,000,000	-	(1,169,324)	96,830,676	1.38%	1,349,562
	2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	(1,534,332)	96,790,668	1.23%	1,207,036
	2004 Series B1	AUC	1/22/04	05/01/32	127,225,000	127,225,000	-	(1,985,912)	125,239,088	1.22%	1,550,569
	2004 Series B2	AUC	1/22/04	10/01/35	19,750,000	19,750,000	-	(307,066)	19,442,934	1.03%	203,715
	2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	(1,834,951)	97,165,049	1.45%	1,431,510
	2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	(1,842,329)	124,457,671	1.52%	1,914,602
					1,085,900,000	1,085,900,000	-	(18,157,933)	1,067,742,067	1.37%	14,887,748
Subtotals					12,706,733,333	13,410,900,000	(35,130,250)	(133,408,280)	13,242,361,470	4.87%	618,440,395
Redemption of Preferred Stock											993,442
Unamortized Loss on Reacquired Debt Expense											6,965,014
Total CECONY					$ 12,706,733,333					**4.93%**	$ 626,398,851

Note:
* Debt outstanding balances and annual costs are prorated for the months outstanding during the period.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
LONG TERM DEBT
Forecast - Rate Year Ended December 31, 2018

	CECONY		Issue Date	Maturity Date	a Amount Outstanding	b Original Issue Amount	c Premium or Discount	d Expense of Issuance	e = b + c + d Net Proceeds	f = g / a Cost of Debt	g Effective Annual Cost
	Debentures:										
	2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	(1,662,326)	172,315,674	5.93%	10,370,728
	2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	(1,866,135)	197,797,865	5.14%	10,273,404
	2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	(1,864,406)	197,597,594	5.74%	11,480,080
	2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	(3,541,534)	345,264,966	5.35%	18,707,834
	2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	(1,142,914)	123,125,836	5.30%	6,624,972
	2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	(3,616,500)	396,323,500	5.88%	23,522,550
	2006 Series B	6.2050%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	(3,669,000)	395,575,000	6.24%	24,967,500
	2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	(2,262,500)	247,025,000	5.74%	14,349,167
	2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	(4,751,250)	517,324,500	6.35%	33,330,850
*	**2008** Series A	5.8500%	4/1/08	04/01/18	150,000,000	600,000,000	(264,000)	(4,099,750)	595,636,250	5.92%	8,884,094
	2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	(5,449,750)	592,792,250	6.79%	40,740,258
*	**2008** Series C	7.1250%	12/2/08	12/01/18	550,000,000	600,000,000	(2,148,000)	(3,962,633)	593,889,367	7.23%	39,747,641
	2009 Series B	6.6500%	3/23/09	04/01/19	475,000,000	475,000,000	(693,500)	(3,284,067)	471,022,433	6.73%	31,985,257
	2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	(5,673,813)	592,058,187	5.54%	33,264,727
	2010 Series A	4.4500%	6/2/10	05/01/20	350,000,000	350,000,000	(759,500)	(2,518,935)	346,721,565	4.54%	15,902,843
	2010 Series B	5.7000%	6/2/10	05/01/40	350,000,000	350,000,000	(1,701,000)	(3,306,369)	344,992,631	5.75%	20,116,912
	2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	(4,228,381)	394,347,619	4.25%	16,988,413
	2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	(6,866,027)	688,261,973	4.01%	28,041,268
	2014 Series A	4.4500%	3/6/14	03/15/44	850,000,000	850,000,000	(714,000)	(8,804,659)	840,481,341	4.49%	38,142,289
	2014 Series B	3.3000%	11/24/14	12/01/24	250,000,000	250,000,000	(867,500)	(2,042,196)	247,090,304	3.42%	8,540,970
	2014 Series C	4.6250%	11/24/14	12/01/54	750,000,000	750,000,000	(1,912,500)	(7,814,167)	740,273,333	4.66%	34,930,667
	2015 Series A	4.5000%	11/17/15	12/01/45	650,000,000	650,000,000	(650,000)	(6,662,500)	642,687,500	4.54%	29,493,750
	2016 Series A	3.8500%	6/1/16	06/01/46	550,000,000	550,000,000	(1,804,000)	(5,637,500)	542,558,500	3.90%	21,423,050
	2016 Series B	3.8200%	11/1/16	11/01/46	750,000,000	750,000,000	(2,460,000)	(7,687,500)	739,852,500	3.87%	28,988,250
	2017 Series A	4.2750%	3/1/17	03/01/47	475,000,000	475,000,000	(1,391,750)	(4,868,750)	468,739,500	4.32%	20,514,933
	2017 Series B	4.2750%	11/1/17	11/01/47	750,000,000	750,000,000	(2,197,500)	(7,687,500)	740,115,000	4.32%	32,392,000
*	**2018** Series A	4.5600%	3/1/18	03/01/48	395,833,333	475,000,000	(669,750)	(4,868,750)	469,461,500	4.60%	18,203,847
*	**2018** Series B	4.5600%	11/1/18	11/01/48	166,666,667	1,000,000,000	(1,410,000)	(10,250,000)	988,340,000	4.60%	7,664,778
					12,387,500,000	13,800,000,000	(38,238,500)	(130,089,811)	13,631,671,689	5.08%	629,593,032
	Tax Exempt Debt Issue through New York State										
	1999 Series A	AUC	7/10/01	05/01/34	292,700,000	292,700,000	-	(4,577,677)	288,122,323	1.74%	5,079,532
	2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	(4,906,341)	219,693,659	2.08%	4,665,013
	2001 Series B	AUC	10/18/01	10/01/36	98,000,000	98,000,000	-	(1,169,324)	96,830,676	1.85%	1,810,162
	2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	(1,534,332)	96,790,668	1.82%	1,792,070
	2004 Series B1	AUC	1/22/04	05/01/32	127,225,000	127,225,000	-	(1,985,912)	125,239,088	1.83%	2,333,003
	2004 Series B2	AUC	1/22/04	10/01/35	19,750,000	19,750,000	-	(307,066)	19,442,934	1.65%	325,178
	2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	(1,834,951)	97,165,049	1.80%	1,778,010
	2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	(1,842,329)	124,457,671	1.88%	2,369,282
					1,085,900,000	1,085,900,000	-	(18,157,933)	1,067,742,067	1.86%	20,152,251
	Subtotals				13,473,400,000	14,885,900,000	(38,238,500)	(148,247,744)	14,699,413,756	4.82%	649,745,283
	Redemption of Preferred Stock										993,442
	Unamortized Loss on Reacquired Debt Expense										6,965,014
	Total CECONY				$ 13,473,400,000					**4.88%**	$ 657,703,739

Note:
* Debt outstanding balances and annual costs are prorated for the months outstanding during the period.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

LONG TERM DEBT

Forecast - Rate Year Ended December 31, 2019

CECONY			Issue Date	Maturity Date	a Amount Outstanding	b Original Issue Amount	c Premium or Discount	d Expense of Issuance	e = b + c + d Net Proceeds	f = g / a Cost of Debt	g Effective Annual Cost
Debentures:											
	2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	(1,662,326)	172,315,674	5.93%	10,370,728
	2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	(1,866,135)	197,797,865	5.14%	10,273,404
	2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	(1,864,406)	197,597,594	5.74%	11,480,080
	2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	(3,541,534)	345,264,966	5.35%	18,707,834
	2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	(1,142,914)	123,125,836	5.30%	6,624,972
	2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	(3,616,500)	396,323,500	5.88%	23,522,550
	2006 Series B	6.2050%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	(3,669,000)	395,575,000	6.24%	24,967,500
	2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	(2,262,500)	247,025,000	5.74%	14,349,167
	2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	(4,751,250)	517,324,500	6.35%	33,330,850
	2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	(5,449,750)	592,792,250	6.79%	40,740,258
*	**2009** Series B	6.6500%	3/23/09	04/01/19	118,750,000	475,000,000	(693,500)	(3,284,067)	471,022,433	6.73%	7,996,314
	2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	(5,673,813)	592,058,187	5.54%	33,264,727
	2010 Series A	4.4500%	6/2/10	05/01/20	350,000,000	350,000,000	(759,500)	(2,518,935)	346,721,565	4.54%	15,902,843
	2010 Series B	5.7000%	6/2/10	05/01/40	350,000,000	350,000,000	(1,701,000)	(3,306,369)	344,992,631	5.75%	20,116,912
	2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	(4,228,381)	394,347,619	4.25%	16,988,413
	2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	(6,866,027)	688,261,973	4.01%	28,041,268
	2014 Series A	4.4500%	3/6/14	03/15/44	850,000,000	850,000,000	(714,000)	(8,804,659)	840,481,341	4.49%	38,142,289
	2014 Series B	3.3000%	11/24/14	12/01/24	250,000,000	250,000,000	(867,500)	(2,042,196)	247,090,304	3.42%	8,540,970
	2014 Series C	4.6250%	11/24/14	12/01/54	750,000,000	750,000,000	(1,912,500)	(7,814,167)	740,273,333	4.66%	34,930,667
	2015 Series A	4.5000%	11/17/15	12/01/45	650,000,000	650,000,000	(650,000)	(6,662,500)	642,687,500	4.54%	29,493,750
	2016 Series A	3.8500%	6/1/16	06/01/46	550,000,000	550,000,000	(1,804,000)	(5,637,500)	542,558,500	3.90%	21,423,050
	2016 Series B	3.8200%	11/1/16	11/01/46	750,000,000	750,000,000	(2,460,000)	(7,687,500)	739,852,500	3.87%	28,988,250
	2017 Series A	4.2750%	3/1/17	03/01/47	475,000,000	475,000,000	(1,391,750)	(4,868,750)	468,739,500	4.32%	20,514,933
	2017 Series B	4.2750%	11/1/17	11/01/47	750,000,000	750,000,000	(2,197,500)	(7,687,500)	740,115,000	4.32%	32,392,000
	2018 Series A	4.5600%	3/1/18	03/01/48	475,000,000	475,000,000	(669,750)	(4,868,750)	469,461,500	4.60%	21,844,617
	2018 Series B	4.5600%	11/1/18	11/01/48	1,000,000,000	1,000,000,000	(1,410,000)	(10,250,000)	988,340,000	4.60%	45,988,667
*	**2019** Series A	4.7100%	3/1/19	03/01/49	791,666,667	950,000,000	(1,311,000)	(9,737,500)	938,951,500	4.75%	37,594,403
					13,035,416,667	13,550,000,000	(37,137,500)	(131,764,928)	13,381,097,572	4.88%	636,531,415
Tax Exempt Debt Issue through New York State											
	1999 Series A	AUC	7/10/01	05/01/34	292,700,000	292,700,000	-	(4,577,677)	288,122,323	2.33%	6,821,097
	2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	(4,906,341)	219,693,659	2.43%	5,451,113
	2001 Series B	AUC	10/18/01	10/01/36	98,000,000	98,000,000	-	(1,169,324)	96,830,676	2.32%	2,270,762
	2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	(1,534,332)	96,790,668	2.42%	2,377,103
	2004 Series B1	AUC	1/22/04	05/01/32	127,225,000	127,225,000	-	(1,985,912)	125,239,088	2.45%	3,115,437
	2004 Series B2	AUC	1/22/04	10/01/35	19,750,000	19,750,000	-	(307,066)	19,442,934	2.26%	446,640
	2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	(1,834,951)	97,165,049	2.15%	2,124,510
	2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	(1,842,329)	124,457,671	2.24%	2,823,962
					1,085,900,000	1,085,900,000	0	(18,157,933)	1,067,742,067	2.34%	25,430,626
Subtotals					14,121,316,667	14,635,900,000	(37,137,500)	(149,922,860)	14,448,839,640	4.69%	661,962,041
Redemption of Preferred Stock											993,442
Unamortized Loss on Reacquired Debt Expense											6,965,014
Total CECONY					$ 14,121,316,667					**4.74%**	$ 669,920,497

Note:

* Debt outstanding balances and annual costs are prorated for the months outstanding during the period.

Consolidated Edison Company of New York, Inc.
Gas Case 16-G-0061
Revenue Summary
For the Twelve Months Ending December 31, 2017
$ 000's

Base rate change in Joint Proposal in Case 16-G-0061 (including temporary credit)	$	35,483
Base rate change approved by the Commission in Case 13-G-0031 effective January 1, 2017 through the expiration of the temporary credit		(40,856)
Base rate change in Joint Proposal in Case 16-G-0061 (excluding temporary credit)	$	(5,373)

Appendix 3 -- Amortization of Regulatory Deferrals (Credit/Debits)

Consolidated Edison Company of New York, Inc.
Electric Case 16-E-0060
Amortization of Regulatory Deferrals
($000's)

	RY1	RY 2	RY 3
Regulatory Assets			
Site Investigation and Remediation (SIR) Program Costs	$ 20,288	$ 26,366	$ 31,871
T&D Deferral Approved in Case 07-E-0523	19,445	4,863	-
BDQM Program - Customer Side	12,836	14,756	14,756
REV -Demonstration Projects	5,520	8,280	11,040
Interference	4,462	4,462	4,462
BDQM Program - Utility Side	3,250	3,250	3,250
System Peak Reduction	1,600	4,000	7,200
Tax Audit Adjustment	872	872	872
Customer Cash Flow Benefits Repair Allowance	644	644	644
Smart Grid Demonstration Grant Program Costs	593	593	593
Management Audit-Northstar	373	373	373
Energy Efficiency	300	2,600	9,900
Reactive Power	215	215	215
Electric Vehicle	78	175	283
Interest on SO2 Allowance Proceeds	24	24	24
Total Regulatory Assets (a)	$ 70,500	$ 71,473	$ 85,483
Regulatory Liabilities			
Property Tax Deferrals	$ 42,639	$ 42,639	$ 42,639
Pensions / OPEBS	38,516	38,516	38,516
Former Employee / Contractor Settlements	23,797	23,797	23,797
Customer Cash Flow Benefits Bonus Depr	13,124	13,124	13,124
Interest Rate True-Up	12,784	12,784	12,784
Carrying Charges Net Plant Reconciliation	7,760	7,760	7,760
Interest on Deferral	3,368	3,368	3,368
Sale of Property- Gain on Luyster Creek Property	3,056	3,056	3,056
Deferred Worker Compensation Recoveries	3,013	3,013	3,013
RRT Lease - NY Transco	2,549	2,549	2,549
Electric Service Reliability Rate Adjustment	1,714	1,714	1,714
Interest on Headroom Capacity	747	747	747
Condemnation of Sprainbrook Properties	483	483	483
Management Variable Pay	268	268	268
Carrying Cost - SIR Deferred Balances	231	231	231
Sale of Air Right 447-453 East 147th St.& 495-501 Brook Ave.	116	116	116
Sale of Property - Gain on Sale of Eylandt (Huguenot)	77	77	77
Total Regulatory Liabilities (b)	$ 154,242	$ 154,242	$ 154,242
Net (credits) / debits (a - b)	$ (83,742)	$ (82,769)	$ (68,759)

Consolidated Edison Company of New York, Inc.
Gas Case 16-G-0061
Amortization of Regulatory Deferrals
($000's)

		RY1	RY 2	RY 3
	Regulatory Assets			
1	Interference	$ 6,517	$ 6,517	$ 6,517
2	SIR	5,024	6,273	7,404
3	Carrying Charges Net Plant Reconciliation	3,809	3,809	3,809
4	Meadowlands Heaters	2,140	2,140	2,140
5	Repair Allowance Interest	367	367	367
6	Management Audit - Northstar	61	61	61
7	Interest on deferred POR	60	60	60
8	Sanford Avenue Gas Explosion	4	4	4
	Total Regulatory Assets (a)	$ 17,982	$ 19,231	$ 20,362
	Regulatory Liabilities			
1	Property Tax Deferrals	$ 18,500	$ 18,500	$ 18,500
2	Case 13-G-0031 Deferral	9,909	9,909	9,909
3	Bonus Depreciation interest	9,011	9,011	9,011
4	Former Employee / Contractor Settlements	4,542	4,542	4,542
5	Pensions / OPEBS	3,514	3,514	3,514
6	Interest Rate True-up	3,398	3,398	3,398
7	Oil to Gas Conversion	2,090	2,090	2,090
8	Penalties on Off-peak / interruptible customers	1,434	1,434	1,434
9	Pipeline integrity	1,085	1,085	1,085
10	Interest on Case 13-G-0031 Deferral	807	807	807
11	Interest on deferred balances	721	721	721
12	Deferred Workers Compensation Recoveries	689	689	689
13	Gain on Sale of Luyster Creek Property	626	626	626
14	Management Variable Pay	52	52	52
15	Unauthorized Use Charge - Divested Stations	42	42	42
16	263a Deferred Taxes	26	26	26
17	Carrying Cost - SIR Deferred Balances	24	24	24
	Total Regulatory Liabilities (b)	$ 56,470	$ 56,470	$ 56,470
	Net (credits) / debits (a - b)	$ (38,488)	$ (37,239)	$ (36,108)

Appendix 4 -- Electric Revenue Forecast

Consolidated Edison Company of New York
Case 16-E-0060
Electric Delivery Volume and Delivery Revenue
Twelve Months ending December 31, 2017, December 31, 2018, and December 31, 2019

	Delivery Volume - GWHs Twelve Months ending December 31st		
	2017	2018	2019
Con Edison Customers	45,156	45,564	45,781
New York Power Authority	9,842	9,811	9,784
Recharge New York	797	797	797
Total Delivery Volumes	55,795	56,172	56,362

	Delivery Revenue at January 1, 2015 Rates - $000s Twelve Months ending December 31st		
Non Competitive	2017	2018	2019
Con Edison Customers*	$4,181,657	$4,225,051	$4,247,067
New York Power Authority	573,849	582,015	588,471
Recharge New York	37,659	37,659	37,659
Reactive Power	$4,943	$4,943	$4,943
Total Delivery Revenues	$4,798,108	$4,849,668	$4,878,140
Competitive			
Billing & Payment Processing	$41,292	$41,586	$41,870
Metering	14,796	15,005	15,126
Merchant Function Charge	68,302	69,846	70,874
Sub Total Competitive Delivery Revenues	$124,390	$126,437	$127,870
Total Delivery Revenues	$4,922,498	$4,976,105	$5,006,010

* Net of Low Income Discounts

Consolidated Edison Company of New York, Inc.
Electric Case 16-E-0060
Other Operating Revenues
($000's)

		RY1 2017	Adjustments	RY2 2018	Adjustments	RY3 2019
1	TCC Credits	$ 75,000	$ -	$ 75,000	$ -	$ 75,000
2	POR Discount	34,548	-	34,548	-	34,548
3	Late Payment Charges	33,192	865	34,057	561	34,618
4	Miscellaneous Service Revenues	19,600	412	20,012	420	20,432
5	Rent from Electric Property	19,313	32	19,345	529	19,874
6	Interdepartmental Rents	17,941	26	17,967	1,107	19,074
7	Transmission of Energy	7,000	-	7,000	-	7,000
8	Transmission Service Revenues	5,000	-	5,000	-	5,000
9	Excess Distribution Facilities	4,042	85	4,127	87	4,214
10	Revenue Imputation- 2004- 2007 Capital Overspend	2,888	(100)	2,788	(100)	2,688
11	Maint. of Interconnection Facilities	2,373	-	2,373	-	2,373
12	Revenue Imputation- Case 09-M-0114 and 09-M-0243	704	(26)	678	(27)	651
13	KeySpan Settlement Facilities Fee	673	-	673	-	673
14	The Learning Center Services	509	11	520	11	531
15	Miscellaneous	111	-	111	-	111
16	AreaWide Contract Fees	59	-	59	-	59
17	Substation Operation Services	46	-	46	-	46
18	NYSERDA On-Bill Recovery Financing Program	17	-	17	-	17
19	ESCO Funding Fees	15	-	15	-	15
20	ESCO Internet Daily / Weekly	-	-	-	-	-
21	Energy Credit	(490)	-	(490)	-	(490)
22	Subtotal	$222,541	$ 1,305	$223,846	$ 2,588	$226,434
23	Amortization of Regulatory Deferrals	83,742	(973)	82,769	(14,010)	68,759
24	Total Other Operating Revenues	$306,283	$ 332	$306,615	$(11,422)	$295,193

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Monthly Electric Revenue Targets

Revenue Targets for Rate Year ending December 2017 (Thousand $)

	SC 1	SC 2 & 6	SC 8	SC 5 & 9	SC 12	CECONY	NYPA	TOTAL
Jan-17	158,896	31,329	10,387	134,022	2,416	337,050	41,668	378,718
Feb-17	149,169	30,537	9,701	125,202	2,366	316,975	48,377	365,352
Mar-17	142,387	29,504	9,471	123,199	2,094	306,655	42,332	348,987
Apr-17	126,302	26,934	8,326	115,824	1,694	279,080	39,021	318,101
May-17	126,002	26,300	8,993	121,441	1,199	283,935	42,314	326,249
Jun-17	159,048	30,491	14,166	177,388	1,402	382,495	59,394	441,889
Jul-17	203,979	35,008	18,781	215,684	1,841	475,293	61,629	536,922
Aug-17	218,905	35,474	19,840	216,892	1,985	493,096	61,811	554,907
Sep-17	194,662	34,457	18,649	218,328	1,763	467,859	64,611	532,470
Oct-17	151,776	29,973	14,484	175,614	1,324	373,171	54,284	427,455
Nov-17	139,467	27,943	9,989	134,206	1,234	312,839	43,789	356,628
Dec-17	150,023	29,956	9,721	129,835	1,928	321,463	42,914	364,377
Rate Year 2017	1,920,616	367,906	152,508	1,887,635	21,246	4,349,911	602,144	4,952,055

Notes:
(1) SC 1 reflects low income discounts of $54.7 million.
(2) SC 9 reflects the exclusion of BIR delivery revenues.
(3) SCs 5, 8, 9, 12, and NYPA reflect the inclusion of Reactive Power revenues.

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Monthly Electric Revenue Targets

Revenue Targets for Rate Year ending December 2018 (Thousand $)

	SC 1	SC 2 & 6	SC 8	SC 5 & 9	SC 12	CECONY	NYPA	TOTAL
Jan-18	172,790	32,982	10,906	137,675	2,468	356,821	43,731	400,552
Feb-18	162,143	32,066	10,193	128,565	2,466	335,433	50,772	386,205
Mar-18	154,826	30,976	9,890	126,455	2,183	324,330	44,412	368,742
Apr-18	140,980	29,019	9,003	124,146	1,747	304,895	42,037	346,932
May-18	140,660	28,342	9,774	130,045	1,223	310,044	44,644	354,688
Jun-18	173,020	32,179	15,028	183,952	1,479	405,658	62,452	468,110
Jul-18	221,386	37,110	19,918	223,376	1,928	503,718	64,856	568,574
Aug-18	236,311	37,323	21,115	222,971	2,076	519,796	65,096	584,892
Sep-18	211,295	36,513	19,764	225,728	1,846	495,146	68,071	563,217
Oct-18	165,001	31,587	15,270	181,064	1,375	394,297	57,334	451,631
Nov-18	150,544	29,134	10,359	136,770	1,284	328,091	46,009	374,100
Dec-18	163,500	31,562	10,146	134,368	2,015	341,591	45,111	386,702
Rate Year 2018	2,092,456	388,793	161,366	1,955,115	22,090	4,619,820	634,525	5,254,345

Notes:
(1) SC 1 revenues are at full customer charge for all customers.
(2) SC 9 reflects the exclusion of BIR delivery revenues.
(3) SCs 5, 8, 9, 12, and NYPA reflect the inclusion of Reactive Power revenues.

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Monthly Electric Revenue Targets

Revenue Targets for Rate Year ending December 2019 (Thousand $)

	SC 1	SC 2 & 6	SC 8	SC 5 & 9	SC 12	CECONY	NYPA	TOTAL
Jan-19	179,705	34,214	11,235	139,244	2,558	366,956	48,423	415,379
Feb-19	172,997	34,188	10,743	134,926	2,485	355,339	50,372	405,711
Mar-19	162,009	32,524	10,293	129,261	2,269	336,356	46,534	382,890
Apr-19	147,975	30,411	9,413	127,641	1,675	317,115	44,131	361,246
May-19	147,915	29,812	10,251	134,232	1,202	323,412	51,113	374,525
Jun-19	182,765	33,945	15,817	190,885	1,481	424,893	59,916	484,809
Jul-19	233,592	38,954	20,987	228,758	2,014	524,305	67,966	592,271
Aug-19	250,264	39,358	22,121	229,232	2,082	543,057	72,593	615,650
Sep-19	224,373	38,531	20,953	233,170	2,060	519,087	67,758	586,845
Oct-19	170,728	32,718	15,757	182,076	1,456	402,735	60,016	462,751
Nov-19	156,894	30,353	10,783	139,558	1,356	338,944	45,733	384,677
Dec-19	173,914	33,536	10,750	140,804	2,011	361,015	50,158	411,173
Rate Year 2019	2,203,131	408,544	169,103	2,009,787	22,649	4,813,214	664,713	5,477,927

Notes:
(1) SC 1 revenues are at full customer charge for all customers.
(2) SC 9 reflects the exclusion of BIR delivery revenues.
(3) SCs 5, 8, 9, 12, and NYPA reflect the inclusion of Reactive Power revenues.

Appendix 5 -- Gas Sales Forecast

Consolidated Edison Company of New York, Inc.
Gas Case 13-G-0031
Sales Revenues
$ 000's

Base Revenues (excl GRT)	Twelve Months Ending December 31, 2017	RY2 Sales Gain/(Loss)	Twelve Months Ending December 31, 2018	RY 3 Sales Gain/(Loss)	Twelve Months Ending December 31, 2019
Service Classification 1	170,919	(117)	170,802	(878)	169,923
Service Classification 2 Rate I	116,038	1,502	117,540	77	117,618
Service Classification 2 Rate II	170,746	690	171,436	852	172,288
Service Classification 2 - DG	6,312	207	6,519	144	6,663
Service Classification 2 - Contract	2,468	-	2,468	-	2,468
Service Classification 3	631,694	21,573	653,267	19,545	672,812
Service Classification 13	453	6	459	8	467
Service Classification 14	381	-	381	-	381
Service Classification 12 R2	13,556	377	13,933	980	14,913
NYPA Demand	2,196	-	2,196	-	2,196
Non-Firm Revenue Retained	65,056	-	65,056	-	65,056
Subtotal	1,179,819	24,239	1,204,058	20,728	1,224,786
Low Income Discount Adj.	(3,500)		(3,500)		(3,500)
Other Surcharges					
BPP	7,903	55	7,958	23	7,981
MFC - Supply	2,948	-	2,948	-	2,948
MFC - Credit & Collections	4,190	-	4,190	-	4,190
MRA - Uncollectable	13	(2)	11	0	11
SBC	14,533	-	14,533	-	14,533
Load Following Charge	-	-	-	-	-
Fuel Revenue	392,527	13,001	405,528	12,814	418,341
GRT on Delivery Revenue	48,925	1,024	49,949	905	50,854
GRT on Competitive Revenues & Other Charges	-	-	-	-	-
Fuel tax	8,249	258	8,507	265	8,772
MRA Credit Tax	-	-	-	-	-
GRT on Low Income Discounts	-	-	-	-	-
Company Use	(672)		(672)		(672)
UBs on MSC Revenue	2,913		2,968		3,016
POR Credit and Collection Charges	(2,361)		(2,361)		(2,361)
Subtotal	479,168	14,336	493,559	14,007	507,614
Grand Total	$ 1,655,487	$ 38,630	$ 1,694,117	$ 34,782	$ 1,728,899

Volumes (Therms)	2017	RY2 Sales Gain/(Loss)	2018	RY 3 Sales Gain/(Loss)	2019
Service Classification 1	43,620,000	100,000	43,720,000	(50,000)	43,670,000
Service Classification 2 Rate I	213,850,000	3,290,000	217,140,000	(1,060,000)	216,080,000
Service Classification 2 Rate II	319,360,000	(720,000)	318,640,000	310,000	318,950,000
Service Classification 2 - DG	30,990,000	-	31,930,000	-	32,550,000
Service Classification 2 - Contract	31,310,000	-	31,310,000	-	31,310,000
Service Classification 3	954,380,000	35,280,000	989,660,000	25,660,000	1,015,320,000
Service Classification 13	840,000	10,000	850,000	10,000	860,000
Service Classification 14	220,000	-	220,000	-	220,000
Service Classification 12 R2	172,210,000		172,210,000	-	172,210,000
	1,766,780,000	**37,960,000**	**1,805,680,000**	**24,870,000**	**1,831,170,000**

Consolidated Edison Company of New York, Inc.
Gas Case 16-G-0061
Other Operating Revenues
($000's)

		RY1 2017	Adjustments	RY2 2018	Adjustments	RY3 2019
1	Interdepartmental Rents	$ 11,555	$ 733	$ 12,288	$ 289	$ 12,577
2	Rents - New York Facilities	5,963	125	6,088	128	6,216
3	Late Payment Charges	5,913	458	6,371	433	6,804
4	POR Discount (Revenue from ESCO)	5,663	-	5,663	-	5,663
5	Misc. Service Revenue	2,660	56	2,716	57	2,773
6	R&D GAC Surcharge	2,000	-	2,000	-	2,000
7	Steam Department - ERRP Incremental Charges	1,215	-	1,215	-	1,215
8	Rents - Real Estate Rents	620	25	645	3	648
9	NYPA Variable and Maintenance	556	12	568	12	580
10	Gas Reconnect Fess	104	2	106	2	108
11	Learning Center Revenues	76	2	78	2	80
12	Revenue Imputation- Case 09-M-0114 and 09-M-0243	173	(7)	166	(6)	160
13	Miscellaneous	2	-	2	-	2
14	Reimbursement To KeySpan-Governor's Island	(44)	(1)	(45)	(1)	(46)
15	Subtotal	$ 36,456	$ 1,405	$ 37,861	$ 919	$ 38,780
16	Amortization of Regulatory Deferrals	38,488	(1,249)	37,239	(1,131)	36,108
17	Total Other Operating Revenues	$ 74,944	$ 156	$ 75,100	$ (212)	$ 74,888

Consolidated Edison Company of New York, Inc.
Case 16-G-0061
Revenue Decoupling Mechanism

The revenue decoupling mechanism ("RDM") will continue to be based on a revenue per customer ("RPC") methodology for customer groups that are included in the RDM.

RPC Methodology:

Under the RPC methodology, Actual Delivery Revenue is compared, on a Rate Year basis, with Allowed Delivery Revenue, which is equal to the product of the average number of customers in the Rate Year and the Rate Year RPC Target for each customer group subject to the RDM. For RDM purposes one customer equals 360 days of service and is measured by the number of annual bills in a Rate Year where one bill equals 30 days of service ("Bill").[1]

Applicability:

The RDM will apply to the following customer groups, including all customers taking service under SC No. 9 that would otherwise take service under such group:

- SC No. 2 –Rate 1;
- SC No. 2 –Rate 2;
- SC No. 3 customers with 1-4 dwelling units; and
- SC No. 3 customers with more than 4 dwelling units.

The groups include: (1) customers taking service under Rider G (Economic Development Zone); (2) all gas volumes associated with customers receiving air conditioning service under SC Nos. 2 and 3; and (3) SC No. 3 customers participating in the Low Income Program described in Section N of the Proposal. The groups exclude: (1) customers who take service under Rider H (Distributed Generation Rate), Rider I (Gas Manufacturing Incentive Rate) and Rider J (Residential Distributed Generation Rate) and (2) customers receiving service under a firm by-pass rate and Excelsior Job customers.

Actual Delivery Revenue:

For the purposes of the RDM, Actual Delivery Revenue, determined for each customer group,

[1] For RDM purposes, the annual number of bills in a Rate Year recognizes equivalent 30-day bills and that customers on average receive bills covering more than 30 days of service in a month and more than 360 days of service in each Rate Year. The definition of customer for RDM purposes does not reflect the actual number of customers subject to the RDM.

will be calculated as the sum of revenue derived from the base tariff rates applicable to SC Nos. 2 and 3, and from the associated SC No. 9 firm transportation tariff rates, and Weather Normalization Adjustment ("WNA") credits or surcharges. Actual Delivery Revenue will not include revenue derived from the RDM Adjustment described below.

SC No. 3 Actual Delivery Revenue will be adjusted for Rate Year 1 to add back the computed cost of the rate discounts provided to Low Income customers based on the number of bills and actual therms delivered to Low Income customers in the two SC No. 3 customer groups. This adjustment will be the same as reported in the annual Low Income program reconciliation for these low income groups. For rate years 2 and 3 low income customers will be billed at full rates but will receive bill credit for the discount. Therefore, no adjustment is necessary for rate years 2 and 3.

Actual Delivery Revenue in the first month of Rate Years 1, 2 and 3 and will be adjusted for the effect of proration of old and new rates on actual revenues. The Adjusted Actual Delivery Revenue for these months for each customer group will be calculated as follows:

1. Any WNA credits or surcharges will be subtracted from Actual Delivery Revenue.
2. Actual delivery revenues will then be reduced by the product of the number of bills times the minimum charge rate.
3. The resulting Actual Delivery Revenue will be adjusted by multiplying it by the ratio of one plus the percentage change in the volumetric rates divided by one plus half of the percentage change in the volumetric rate (Factor 1).
4. The resulting adjusted Actual Delivery Revenue will be increased by the amount reflected in step 2.
5. The WNA credits subtracted in step 1 above will be adjusted and added back, resulting in Adjusted Actual Delivery Revenue. Actual WNA revenues will be adjusted by one half of the percentage change between the old and new penultimate rates. Any impact in the first month of Rate Year 1 due to the change in the definition of normal weather from a 10 year average condition to a 30 year average condition will be captured in the reconciliation provisions of the Revenue Decoupling Mechanism.

	Factor 1		
	RY1	**RY2**	**RY3**
SC No. 2 – Rate 1	0.9873	1.0255	1.0144
SC No. 2 – Rate 2	1.0130	1.0435	1.0392
SC3 customers with 1-4 dwelling units	1.0158	1.0447	1.0398
SC3 customers with more than 4 dwelling units	1.0158	1.0672	1.0592

RPC Targets:

The RPC Target for each customer group will be set for each Rate Year at 12 times the average

Delivery Revenue per Bill, as shown in Table 2. The average Delivery Revenue per Bill is calculated by dividing the total Rate Year Delivery Revenues (revenue derived from the base rates applicable to SC Nos. 2 and 3, and from the corresponding SC No. 9 firm transportation rates) by the number of Bills in the Rate Year.

The Bills for the RPC Targets will be based on the forecasted Rate Year number of Bills used to set rates, as shown below:

	RY1	RY2	RY3
SC No. 2 – Rate 1	733,352	740,382	745,248
SC No. 2 – Rate 2	832,885	843,239	851,660
SC3 customers with 1-4 dwelling units	3,522,835	3,601,534	3,663,532
SC3 customers with more than 4 dwelling units	266,074	276,977	285,737

The Delivery Revenues, by customer class, that will be used to calculate the RPC Targets are shown below. For SC No. 3, the Delivery Revenues shown below are computed assuming all Low Income customers are billed at full rates.

	RY1	RY2	RY3
SC No. 2 – Rate 1	$113,713,709	$118,760,876	$121,774,111
SC No. 2 – Rate 2	$174,577,428	$188,469,677	$202,016,817
SC3 customers with 1-4 dwelling units	$314,851,026	$339,182,570	$362,452,861
SC3 customers with more than 4 dwelling units	$340,919,851	$389,479,137	$437,988,248

The RPC Targets for all rate years for each customer group are shown below.

	RY1	RY2	RY3
SC No. 2 – Rate 1	$1,860.72	$1,924.86	$1,960.81
SC No. 2 – Rate 2	$2,515.27	$2,682.08	$2,846.44
SC3 customers with 1-4 dwelling units	$1,072.49	$1,130.13	$1,187.22
SC3 customers with more than 4 dwelling units	$15,375.57	$16,874.14	$18,394.04

RDM Adjustment:

For each customer group subject to the RDM, the Company will, at the end of each Rate Year, compare Actual Delivery Revenue to the Allowed Delivery Revenue. To the extent that the Actual Delivery Revenue varies from the Allowed Delivery Revenue, the excess or shortfall will be refunded to or collected from customers through customer group-specific RDM Adjustments over a twelve-month period commencing in the second month following the end of each Rate Year.

The customer group-specific RDM Adjustments will be determined on a cents per therm basis by dividing the total revenue excess/shortfall for each customer group by the forecasted therm deliveries of the associated customer group for the period in which the RDM Adjustment is to be in effect.

Beginning with the first month following the end of each Rate Year, interest at the Other Customer Provided Capital Rate will be calculated for each month on the average of the current and prior month's cumulative revenue over- or under-collection (net of state and federal taxes) and will be included along with the over- or under-collection charged or credited to customers.

Interim RDM Adjustment:

The Company may implement an Interim RDM Adjustment whenever the Company determines that such a surcharge or credit adjustment is necessary to avoid a large over- or under-collection, based on the Company's projection for the Rate Year of forthcoming RDM reconciliation balances. At least two weeks prior to the Company's implementing an Interim RDM Adjustment, the Company will provide Staff work papers underlying such surcharge or credit adjustment in order to afford Staff an opportunity to raise with the Company any concerns that Staff has with the size and/or timing of the surcharge or credit adjustment.[2] Any Interim RDM Adjustment will be determined based on a 12- month recovery period. Revenues associated with Interim RDM Adjustments will be included in the annual RDM reconciliation.

Partial Year RDM:

If the Company does not file for new base delivery rates to take effect within fifteen days after the expiration of RY3, the RDM will be implemented as follows. Prior to the start of RY3, the Company will provide, along with the RY3 annual RPC targets, the monthly RPC targets associated with the RY3 annual RPC targets. To the extent the stay-out period beyond RY3 is less than 12 months, these monthly RPC targets will be used to implement the RDM in the stay-out period. The provisions of the calculation of the annual true-up on a full-year basis would also apply to any partial year, that is, the monthly RPC targets for the months of the partial year period would be summed, and then multiplied by the average monthly number of Bills for the partial year period to derive the partial year period Allowed Delivery Revenue. This Allowed Delivery Revenue would be compared to the Actual Delivery Revenue for the partial year period to determine any excess or shortfall. During the term of the Gas Rate Plan, the Company will provide data on actual bills and revenues unless and until changed by Commission order.

[2] The Company will provide to interested parties, upon request, a copy of any such work papers after the filing is made.

Appendix 6 -- Safety and Reliability Surcharge Mechanism

Consolidated Edison Company of New York, Inc.
Case 16-G-0061
Safety and Reliability Surcharge Mechanism (SRSM)

The Safety and Reliability Surcharge Mechanism ("SRSM") allows Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") to: 1.) recover the carrying costs on incremental capital expenditures and O&M expenses associated with the replacement of Leak Prone Pipe ("LPP") above the levels established under the Gas Rate Plan; and 2.) recover incremental O&M expenses associated with lowering the Company's leak backlog.

A. LPP Replacement

The SRSM allows Con Edison to recover the carrying costs on incremental capital expenditures and O&M expenses associated with the replacement of LPP above the levels established under the Gas Rate Plan, subject to the conditions set forth below:

1.) Both the actual costs of LPP replacement incurred by the Company in total across all regions and the actual LPP footage replaced by the Company under the Main Replacement Program[1] as of the end of the applicable Rate Year must exceed the targets[2] shown below in Table 1:

Table 1	2017 (RY1)	2018 (RY2)	2019 (RY3)
Miles of Main Replaced	70	75	80
Capital Spending (000's)	$282,351	$316,895	$351,513

2.) Incremental actual costs are recoverable up to the capital and O&M caps set forth below in Table 2:

Table 2 Capital Cost Cap Per Mile by Area	2017 (RY1)	2018 (RY2)	2019 (RY3)
Manhattan	$8,745,810	$8,913,233	$9,173,731
Queens	$3,463,176	$3,534,215	$3,591,500
Bronx	$4,633,492	$4,723,097	$4,875,024
Westchester	$2,931,589	$2,956,568	$3,110,255
O&M Cost Cap Per Mile by Area	**2017**	**2018**	**2019**

[1] This covers the following programs listed under Exhibit GIOP-1: Replace Corroded Steel Mains, Replace Cast Iron Mains and Services Associated with Main Work.

[2] The Company must also meet the overall targets in each rate year (*i.e.*, 80 in RY1, 85 in RY2 and 90 in RY3) to be eligible for recovery under this mechanism.

	(RY1)	(RY2)	(RY3)
Manhattan	$657,746	$657,746	$657,746
Queens	$79,314	$79,314	$79,314
Bronx	$166,534	$166,534	$166,534
Westchester	$47,791	$47,791	$47,791

3.) Recovery of the incremental costs is to begin no earlier than March 1st of each year following the end of the applicable Rate Year (*e.g.*, recovery of incremental O&M costs incurred in RY1 will begin on March 1, 2018 and be recovered over a 12 month period through February 2019 while the carrying charges associated with the incremental capital costs will be recovered until base rates are reset in the next rate case). Carrying charges on incremental capital associated with the new mains will be calculated based on a book life of 85 years, a tax life of 20 years, and an estimated property tax factor of 5%.

Page 3 of this Appendix provides several examples that demonstrate how the LPP portion of the SRSM will work under various potential scenarios. Page 4 of this appendix provides an example of the capital carrying costs calculation.

B. Leak Backlog

The SRSM will also allow the Company to recover incremental O&M expenses associated with lowering the Company's leak backlog, subject to the conditions set forth below:

1.) The actual leak backlog level the Company achieves is below the applicable Rate Year target (as described in the Gas Performance Measures Appendix 16) and the Company exceeds the annual rate allowance for leak repairs as set forth in Table 3:

Table 3	2017 (RY1)	2018 (RY2)	2019 (RY3)
O&M Spending (000's)	$52,580	$52,184	$52,035

2.) Recovery will be capped at the lesser of the total incremental cost or $5,100 per actual leak repaired below the applicable target.

3.) Recovery of the incremental costs is to begin no earlier than March 1st, of each year following the end of the applicable Rate Year (*e.g.*, recovery of incremental O&M costs incurred in RY1 will begin on March 1, 2018 and be recovered over a 12 month period through February 2019).

Consolidated Edison Company of New York, Inc.
Gas Case 16-G-0061
Safety and Reliability Surcharge Mechanism Incremental Cost Example
($000's)

LLP Example for 2017 (RY1)

Targets	**Manhattan**	**Queens**	**Bronx**	**Westchester**	**Total**
Target Mileage	8	12	14	36	70
Target Capital	$ 70,632,354	$ 40,434,548	$ 66,885,510	$ 104,497,822	$ 282,450,234
$Capital/Mile Cap	$ 8,745,810	$ 3,463,176	$ 4,633,492	$ 2,931,589	
Target O&M	$ 5,312,046	$ 926,036	$ 2,403,956	$ 1,703,532	$ 10,345,570
$O&M/M Cap	$ 657,746	$ 79,314	$ 166,534	$ 47,791	
LPP MAC Factor	8%	2%	4%	2%	

Scenario 1	**Manhattan**	**Queens**	**Bronx**	**Westchester**	**Total**
Actual Mileage	7	11	12	39	69
Actual Capital	$ 72,000,000	$ 35,000,000	$ 68,000,000	$ 110,000,000	$ 285,000,000
Actual Capital/Mile	$ 10,285,714	$ 3,181,818	$ 5,666,667	$ 2,820,513	
Recoverable Capital	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Scenario 1 Result: No additional recovery, total target miles not exceeded.

Scenario 2	**Manhattan**	**Queens**	**Bronx**	**Westchester**	**Total**
Actual Mileage	8	14	15	36	73
Actual Capital	$ 72,000,000	$ 40,000,000	$ 64,000,000	$ 104,000,000	$ 280,000,000
Actual Capital/Mile	$ 9,000,000	$ 2,857,143	$ 4,266,667	$ 2,888,889	
Recoverable Capital	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Scenario 2 Result: No additional recovery, total target capital costs not exceeded.

Scenario 3	**Manhattan**	**Queens**	**Bronx**	**Westchester**	**Total**
Actual Mileage	8	10	15	41	74
Actual Capital	$ 68,000,000	$ 35,000,000	$ 70,000,000	$ 110,000,000	$ 283,000,000
Actual Capital/Mile	$ 8,500,000	$ 3,500,000	$ 4,535,081	$ 2,706,330	
Incremental Miles			1	5	4
Incremental Cost Spent over Target Capital (A)			**3,114,490**	**5,502,178**	**549,766**
Incremental Cost/Mile			3,114,490	1,100,436	
Lessor of Actual or Cap Cost/Mile			3,114,490	1,100,436	
Incremental Cost at Cost/Mile Cap (B)			**3,114,490**	**5,502,178**	**8,616,667**
Recoverable O&M (capital x O&M factor)			111,939	89,697	201,636
Recoverable Capital *(the lesser of A or B total)*					**$ 549,766**

Scenario 3 Result: Company recovers carrying costs on $550K of incremental capital plus $202K of incremental O&M.

Scenario 4	**Manhattan**	**Queens**	**Bronx**	**Westchester**	**Total**
Actual Mileage	8	13	16	38	75
Actual Capital	$ 68,000,000	$ 45,000,000	$ 76,000,000	$ 110,000,000	$ 299,000,000
Actual Capital/Mile	$ 8,500,000	$ 3,550,137	$ 4,624,214	$ 2,922,000	
Incremental Miles	0	1	2	2	5
Incremental Cost Spent over Target Capital (A)		4,565,452	9,114,490	5,502,178	16,549,766
Incremental Cost/Mile		4,565,452	4,557,245	2,751,089	
Lessor of Actual or Cap Cost/Mile		3,463,176	4,557,245	2,751,089	
Incremental Cost at Cost/Mile Cap (B)		**3,463,176**	**9,114,490**	**5,502,178**	**14,616,667**
Recoverable O&M (capital x O&M factor)		79,314	327,587	89,697	496,598
Recoverable Capital *(the lesser of A or B)*		**$ 3,463,176**	**$ 9,114,490**	**$ 5,502,178**	**$ 14,616,667**

Scenario 4 Result: Company recovers carrying costs on $14.616M of incremental capital plus $497K of incremental O&M.

Consolidated Edison Company of New York, Inc.

Gas Case 16-G-0061

Example of Revenue Requirement Calculation for Safety and Reliability Surcharge Mechanism

Assumed incremental capital amount spent in RY1,
meets all requirements for recovery. $ 14,616,667

	2017	2018	2019
Average Net Plant in Service	7,239,270	14,340,412	14,064,157
Average Deferred FIT and SIT Balance*	(38,974)	(155,894)	(417,340)
Average Net Rate Base	7,200,296	14,184,518	13,646,818
Pre Tax Rate of Return	9.61%	9.59%	9.52%
Earnings Base	695,694	1,375,246	1,338,908
Earnings - Expenses			
Income Tax - Removal Cost	29,885	59,770	59,770
Book Depreciation**	138,128	276,255	276,255
Property Taxes***	361,963	723,927	723,927
Total Earnings Effects	1,225,670	2,435,198	2,398,860
Gross-Up Factor	1.04	1.04	1.04
Revenue Requirement	$ 1,275,187	$ 2,533,580	$ 2,495,774

2017+2018 to be recovered March 2018 to February 2019 1/12th per mon	$ 3,808,767	
2019 to be recovered March 2019 to February 2020**** 1/12 per month		$ 2,495,774

Notes:
*Assumed tax life of 20 years
**Assumed book life of 85 years
***Assumed estimated property tax factor of 5%
****Surcharge recovery will end in December 2019 if new rates go into effect January 2020.

Appendix 7 -- Gas LAUF

Consolidated Edison Company of New York, Inc
Calculation of Five-Year Average Line Loss Factor, Factor of Adjustment, and Incentive/Penalty bands
Based on 5 Year Period: TME Aug 11 to TME Aug 15

		Aug-15	Aug-14	Aug-13	Aug-12	Aug-11
	Citygate Receipts					
1.	Total Pipeline Receipts	391,451,202	377,356,324	353,025,876	330,946,295	342,972,760
2.	LNG Withdrawals	490,659	140,655	64,064	104,271	99,052
3.	Total Receipts from NY Facilities	3,664,374	3,903,022	10,249,629	5,128,958	3,271,542
4.	**Total Receipts (Sum of Lines 1-3)**	395,606,235	381,400,001	363,339,569	336,179,524	346,343,354
	Deliveries to Customers					
5.	Retail Sales and Transportation Deliveries	180,059,780	169,409,530	153,245,546	132,737,852	149,664,074
6.	Deliveries to Generation	168,653,886	170,829,620	170,834,882	165,278,604	150,306,718
7.	Gas Used for Company Purposes & CNG	138,392	146,894	161,513	165,463	136,113
8.	LNG Injections	1,154,060	201,586	273,800	13,066	162,480
9.	Total Heater & Compressor Consumption	477,636	328,306	405,119	370,097	357,530
10.	Total Deliveries to NY Facilities	37,960,412	35,826,881	34,253,075	34,006,479	40,384,365
11.	**Total Deliveries (Sum of Lines 5-10)**	388,444,166	376,742,817	359,173,935	332,571,561	341,011,279
12.	**Losses (Line 4 - Line 11)**	7,162,069	4,657,184	4,165,634	3,607,963	5,332,075
	Contribution to system line loss from Generation at 0.5%					
13.	**(Line 6 * 0.005)**	843,269	854,148	854,174	826,393	751,534
14.	**Adjusted Line Loss (Line 12 - Line 13)**	6,318,800	3,803,036	3,311,459	2,781,570	4,580,541
15.	**Citygate Receipts adjusted for Generation (Line 4 - Line 6 - Line 13)**	226,109,080	209,716,233	191,650,513	170,074,527	195,285,102
16.	***Annual Line Loss Factor (LLF) (Line 14 / Line 15)***	2.7946%	1.8134%	1.7279%	1.6355%	2.3456%

5-Year Statistics (Aug 11 - Aug 15)

	Five-Year average Line Loss Factor (LLF)	
17.	**(Average of Line 16)**	**2.063%**
	Std Deviation	**0.493%**
	2 Std Deviations	**0.986%**
18.	**Standard Deviation (SD) of Line 16**	**0.493%**
	LLF% Target	**2.063%**
	Upper Deadband Limit	
19.	**(Line 17 + (2* Line 18))**	**3.049%**
	Lower Deadband Limit	
20.	**(Line 17 - (2* Line 18))**	**1.077%**
	Factor of Adjustment	
21.	**1/(1-Line 17)**	**1.0211**
	Maximuxm Upper Limit	
22	**(Line 17 + (4* Line 18))**	**4.036%**
	Maximum Lower Limit	
23	**(Line 17 - (4* Line 18))**	**0.091%**
24	**Total Receipts W/O Gen (Line 4 - Line 6 - Line 13)**	**226,109,080**
25	**Total Deliveries W/O Gen (Line 11 - Line 6)**	**219,790,280**

DETERMINE LLF% TARGET & DEAD BAND
Basis: Target & Dead Band are calculated from 5 years of historical data
Dead Band is equal to +/- 2 standard deviations

Consolidated Edison Company of New York, Inc
SAMPLE CALCULATION OF LINE LOSS BENEFIT/(COST)

	Losses Below lower deadband limit	Losses within deadband of +/- two std deviations	Losses Above upper deadband limit	
1. Total Receipts	391,406,235	393,606,235	396,356,235	
2. Total Deliveries	388,444,166	388,444,166	388,444,166	
3. Line Loss (Line 1 - Line 2)	2,962,069	5,162,069	7,912,069	
4. Deliveries to Generators	168,653,886	168,653,886	168,653,886	
5. Contributions from Generators (Line 4 * 0.005)	843,269	843,269	843,269	
6. Adjusted Line Loss (Line 3 - Line 5)	2,118,800	4,318,800	7,068,800	
7. Receipts Adjusted for Generators (Line 1 - Line 4 - Line 5)	221,909,080	224,109,080	226,859,080	
8. Adjusted Line Loss Factor (Line 6 / Line 7)	0.955%	1.927%	3.116%	
9. Annual Factor of Adjustment (1/1-Line 8)	1.0096	1.0196	1.0322	
10. **Target 5 yr Avg Line Loss Factor (Appendix 7 Page 1)**	**2.063%**	**2.063%**	**2.063%**	
11. **Factor of Adjustment (FOA) (1/1-Line 10)**	**1.0211**	**1.0211**	**1.0211**	
12. Net Commodity Cost of Gas	$ 254,464,905	$ 254,464,905	$ 254,464,905	
13. Upper Limit of Deadband (LLF) (App 7 Line 19)	3.049%	3.049%	3.049%	
14. Upper Limit of DB (FOA)(1/1-Line 13)	1.0315	1.0315	1.0315	
15. Lower Limit of DB (LLF) (App 7 Page 1 Line 20)	1.077%	1.077%	1.077%	
16. Lower Limit of Deadband (FOA)(1/1-Line 15)	1.0109	1.0109	1.0109	Lower Limit of Deadband (FOA)(1/1-Line 15)
17. Company Benefit/(Cost)*	$315,036		($174,400)	

A cost is subtracted from the gas costs to be recovered from gas sales customers and a benefit is added to the gas costs to be recovered from gas sales customers.

If the actual LLF is less than the Upper Limit of Deadband (LLF) and greater than Lower Limit of Deadband (LLF) then there is no benefit or cost

If the actual LLF is greater than the Upper Limit of Deadband (LLF)
Penalty (Cost) - Line 12 x [(Line 14 / Line 9) - 1]

If the actual LLF is less than the Lower Limit of Deadband (LLF)
Benefit = Line 12 x [(Line 16 / Line 9) - 1]

Appendix 8 -- Electric Reconciliation Targets

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Electric True Up Targets
$ 000's

	Twelve Months Ending December 31,				
Revenue True-ups	2017	RY2 Change	2018	RY3 Change	2019
Proceeds from Sales of TCCs	$ 75,000	$ -	$ 75,000	$ -	$ 75,000
Transmission Service Charges	5,000	-	5,000	-	5,000
Transmission of Energy	7,000	-	7,000	-	7,000
Environmental Allowances (SO2)*	-	-	-	-	-
Expense True-ups					
Municipal Infrastructure Support					
Interference - excl. Company labor (80/20 True up)	95,109	2,628	97,737	(706)	97,031
Property Tax Expense (90/10 True up)					
New York City	1,178,119	63,785	1,241,904	65,081	1,306,985
Upstate and Westchester	140,853	6,512	147,365	8,105	155,470
Total Property Taxes	1,318,972	70,297	1,389,269	73,186	1,462,455
Employee Pensions	203,086	(24,463)	178,623	(46,639)	131,984
Other Post Employment Benefits	(12,755)	3,779	(8,976)	(3,656)	(12,631)
Pension / OPEB Expense Before Phase In Adjustment	190,331	(20,684)	169,647	(50,295)	119,352
Adjustment to match expense with rate allowance -Levelization	(43,526)	43,489	(36)	43,598	43,562
Net Pension / OPEB Expense Rate Allowance	146,805	22,805	169,611	(6,697)	162,914
Storm Reserve	21,427	-	21,427	-	21,427
Management Variable Pay (Net of Capitalized)	27,238	602	27,840	615	28,455
ERRP - Major Maintenance	10,704	-	10,704	-	10,704
NEIL Insurance*	-	-	-	-	-
AMI Customer Engagement and Rate Pilot	3,184	6,005	9,189	650	9,839
Electric Vehicle Rate Incentive	641	392	1,033	392	1,425
Rate Base True-ups					
BQDM	92,877	(5,078)	87,799	(5,078)	82,721
REV Demo Projects	31,870	3,355	35,225	10,064	45,290
Energy Efficiency	821	7,018	7,840	25,375	33,214
Electric Vehicle (Equipment)	213	454	666	482	1,148
System Peak Reduction	4,376	10,454	14,829	13,614	28,443
SIR	55,485	(16,024)	39,461	(19,369)	20,092
Interest True-Ups (page 2)					
Average Variable Rate	1.37%	0.49%	1.86%	0.48%	2.34%
Variable Rate Debt Cost	11,036,310	3,717,150	14,753,460	3,656,670	18,410,130
Corporate Income Tax					
Brownfield Tax Credits*	-	-	-	-	-

Note
* The Company will defer for the benefit of customers all SO_2 allowances, NEIL Dividends, and Brownfield Tax Credits received during the term of the plan.

Consolidated Company of New York, Inc.
Cases 16-E-0060 / 16-G-0061
Variable Rate Debt

			RY1		RY2		RY3	
Bond	Maturity Date	Amount Outstanding	Effective Cost of Money	Effective Annual Cost	Effective Cost of Money	Effective Annual Cost	Effective Cost of Money	Effective Annual Cost
1999 Series A	05/01/34	292,700,000	1.15%	3,351,839	1.74%	5,079,532	2.33%	6,821,097
2010 Series A	06/01/36	224,600,000	1.73%	3,878,913	2.08%	4,665,013	2.43%	5,451,113
2001 Series B	10/01/36	98,000,000	1.38%	1,349,562	1.85%	1,810,162	2.32%	2,270,762
2004 Series A	01/01/39	98,325,000	1.23%	1,207,036	1.82%	1,792,070	2.42%	2,377,103
2004 Series B1	05/01/32	127,225,000	1.22%	1,550,569	1.83%	2,333,003	2.45%	3,115,437
2004 Series B2	10/01/35	19,750,000	1.03%	203,715	1.65%	325,178	2.26%	446,640
2004 Series C	11/01/39	99,000,000	1.45%	1,431,510	1.80%	1,778,010	2.15%	2,124,510
2005 Series A	05/01/39	126,300,000	1.52%	1,914,602	1.88%	2,369,282	2.24%	2,823,962
		1,085,900,000	1.37%	14,887,748	1.86%	20,152,251	2.34%	25,430,626

	RY1	RY2	RY3
Total costs	**$ 14,887,748**	**$ 20,152,251**	**$ 25,430,626**
Allocation to Electric*	74.1%	73.2%	72.4%
Electric Target	**$ 11,036,310**	**$ 14,753,460**	**$ 18,410,130**
Allocation to Gas*	19.8%	21.1%	22.2%
Gas Target	**$ 2,952,300**	**$ 4,246,900**	**$ 5,642,600**
Allocation to Steam*	6.0%	5.7%	5.4%
Steam Target	**$ 899,140**	**$ 1,151,890**	**$ 1,377,900**

* Interest costs will be allocated monthly based on the ratio of actual electric, gas, and steam plant to total plant.

	RY1	RY2	RY3
Net Utility Plant (Electric)	$ 22,001,169	$ 22,957,855	$ 23,949,003
Net Utility Plant (Gas)	5,885,477	6,608,602	7,340,228
Net Utility Plant (Steam)	1,792,456	1,792,456	1,792,456
	$ 29,679,102	$ 31,358,913	$ 33,081,687
Elec Allocation	74.1%	73.2%	72.4%
Gas Allocation	19.8%	21.1%	22.2%
Steam Allocation	6.0%	5.7%	5.4%
	100.0%	100.0%	100.0%

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Electric Average Net Plant Target Excludes AMI
$ 000's

Target

Exluding BQDM	BOOK COST OF PLANT	ACCRUED DEPRECIATION	DEPRECIATION REMOVAL COST	AVERAGE NET PLANT EXCLUDING REMOVAL COST
RY1	28,482,426	(6,692,931)	(109,908)	21,679,587
RY2	29,772,672	(7,161,567)	(290,437)	22,320,667
RY3	31,160,180	(7,711,898)	(462,426)	22,985,856

BQDM	BOOK COST OF PLANT	ACCRUED DEPRECIATION	DEPRECIATION REMOVAL COST	AVERAGE NET PLANT EXCLUDING REMOVAL COST
RY1	9,488	(62)	-	9,426
RY2	17,646	(499)	-	17,147
RY3	17,646	(1,001)	-	16,645

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Carrying Charge Rates

RY 1

	Electric Plant	BQDM	AMI Plant
Pre Tax Overall Rate of Return	9.610%	9.610%	9.610%
Composite Book Depreciation Rate	3.165%	2.842%	9.010%
Total Carrying Charge Rate	12.775%	12.452%	18.620%

RY 2

	Electric Plant	BQDM	AMI Plant
Pre Tax Overall Rate of Return	9.590%	9.590%	9.590%
Composite Book Depreciation Rate	3.154%	2.842%	8.345%
Total Carrying Charge Rate	12.744%	12.432%	17.935%

RY 3

	Electric Plant	BQDM	AMI Plant
Pre Tax Overall Rate of Return	9.520%	9.520%	9.520%
Composite Book Depreciation Rate	3.165%	2.842%	7.333%
Total Carrying Charge Rate	12.685%	12.362%	16.853%

Appendix 9 -- Gas Reconciliation Targets

Consolidated Edison Company of New York, Inc.
Case 16-G-0061
Gas True Up Targets
$ 000's

	2017	RY2 Change	2018	RY3 Change	2019
	Twelve Months Ending December 31,				
Expense True-ups					
Municipal Infrastructure Support					
Interference - excl. Company labor (80/20 True up)	$ 27,556	$ (45)	$ 27,511	$ (1,354)	$ 26,157
Property Tax Expense (90/10 True up)					
New York City	172,668	26,172	198,840	28,457	227,297
Upstate and Westchester	56,189	3,090	59,279	3,260	62,539
Total Property Taxes	228,857	29,262	258,119	31,717	289,836
Employee Pensions	41,743	(5,029)	36,714	(9,586)	27,128
Other Post Employment Benefits	(2,622)	777	(1,845)	(751)	(2,596)
Pension / OPEB Expense	39,121	(4,252)	34,869	(10,337)	24,532
Management Variable Pay (Net of Capitalized)	5,511	122	5,633	124	5,758
Pipeline Integrity Costs	4	0	4	0	4
Research and Development (Internal Programs)	1,132	24	1,156	24	1,180
AMI Customer Engagement	16	801	817	376	1,193
Rate Base True-ups					
SIR	13,740	(3,812)	9,928	(4,500)	5,428
Interest True-Ups (page 2)					
Average Variable Rate	1.37%	0.49%	1.86%	0.48%	2.34%
Variable Rate Debt Cost	2,952,300	1,294,600	4,246,900	1,395,700	5,642,600

Consolidated Company of New York, Inc.
Cases 16-E-0060 / 16-G-0061
Variable Rate Debt

Bond	Maturity Date	Amount Outstanding	RY1 Effective Cost of Money	RY1 Effective Annual Cost	RY2 Effective Cost of Money	RY2 Effective Annual Cost	RY3 Effective Cost of Money	RY3 Effective Annual Cost
1999 Series A	05/01/34	292,700,000	1.15%	3,351,839	1.74%	5,079,532	2.33%	6,821,097
2010 Series A	06/01/36	224,600,000	1.73%	3,878,913	2.08%	4,665,013	2.43%	5,451,113
2001 Series B	10/01/36	98,000,000	1.38%	1,349,562	1.85%	1,810,162	2.32%	2,270,762
2004 Series A	01/01/39	98,325,000	1.23%	1,207,036	1.82%	1,792,070	2.42%	2,377,103
2004 Series B1	05/01/32	127,225,000	1.22%	1,550,569	1.83%	2,333,003	2.45%	3,115,437
2004 Series B2	10/01/35	19,750,000	1.03%	203,715	1.65%	325,178	2.26%	446,640
2004 Series C	11/01/39	99,000,000	1.45%	1,431,510	1.80%	1,778,010	2.15%	2,124,510
2005 Series A	05/01/39	126,300,000	1.52%	1,914,602	1.88%	2,369,282	2.24%	2,823,962
		1,085,900,000	1.37%	14,887,748	1.86%	20,152,251	2.34%	25,430,626

	RY1	RY2	RY3
Total costs	**$ 14,887,748**	**$ 20,152,251**	**$ 25,430,626**
Allocation to Electric*	74.1%	73.2%	72.4%
Electric Target	**$ 11,036,310**	**$ 14,753,460**	**$ 18,410,130**
Allocation to Gas*	19.8%	21.1%	22.2%
Gas Target	**$ 2,952,300**	**$ 4,246,900**	**$ 5,642,600**
Allocation to Steam*	6.0%	5.7%	5.4%
Steam Target	**$ 899,140**	**$ 1,151,890**	**$ 1,377,900**

* Interest costs will be allocated monthly based on the ratio of actual electric, gas, and steam plant to total plant.

	RY1	RY2	RY3
Net Utility Plant (Electric)	$ 22,001,169	$ 22,957,855	$ 23,949,003
Net Utility Plant (Gas)	5,885,477	6,608,602	7,340,228
Net Utility Plant (Steam)	1,792,456	1,792,456	1,792,456
	$ 29,679,102	$ 31,358,913	$ 33,081,687
Elec Allocation	74.1%	73.2%	72.4%
Gas Allocation	19.8%	21.1%	22.2%
Steam Allocation	6.0%	5.7%	5.4%
	100.0%	100.0%	100.0%

Consolidated Edison Company of New York, Inc.
Case 16-G-0061
Gas Average Net Plant Target Excluding AMI
$ 000's

	Target			
	BOOK COST OF PLANT	**ACCRUED DEPRECIATION**	**DEPRECIATION REMOVAL COST**	**AVERAGE NET PLANT EXCLUDING REMOVAL COST**
RY1	7,438,440	(1,579,494)	(14,411)	5,844,535
RY2	8,241,564	(1,689,862)	(39,349)	6,512,353
RY3	9,066,574	(1,825,978)	(63,589)	7,177,007

Consolidated Edison Company of New York, Inc.
Case 16-G-0061
Carrying Charge Rates

RY 1

	Gas Plant	AMI Plant
Pre Tax Overall Rate of Return	9.610%	9.610%
Composite Book Depreciation Rate	2.457%	8.784%
Total Carrying Charge Rate	12.067%	18.394%

RY 2

	Gas Plant	AMI Plant
Pre Tax Overall Rate of Return	9.590%	9.590%
Composite Book Depreciation Rate	2.434%	7.834%
Total Carrying Charge Rate	12.024%	17.424%

RY 3

	Gas Plant	AMI Plant
Pre Tax Overall Rate of Return	9.520%	9.520%
Composite Book Depreciation Rate	2.426%	6.482%
Total Carrying Charge Rate	11.946%	16.002%

Appendix 10 -- AMI Reconciliation Targets

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Electric Average AMI Net Plant Target
$ 000's

	Target			
	BOOK COST OF PLANT	**ACCRUED DEPRECIATION**	**DEPRECIATION REMOVAL COST**	**AVERAGE NET PLANT EXCLUDING REMOVAL COST**
RY1	130,441	(4,594)	-	125,847
RY2	278,847	(21,745)	-	257,102
RY3	465,162	(49,787)	-	415,375

	CAPITAL SPEND
RY1	141,860
RY2	154,121
RY3	218,391

Consolidated Edison Company of New York, Inc.
Case 16-G-0061
Gas Average AMI Net Plant Target
$ 000's

	Target			
	BOOK COST OF PLANT	ACCRUED DEPRECIATION	DEPRECIATION REMOVAL COST	AVERAGE NET PLANT EXCLUDING REMOVAL COST
RY1	27,474	(943)	-	26,531
RY2	61,373	(4,471)	-	56,902
RY3	109,918	(10,280)	-	99,638

	CAPITAL SPEND
RY1	30,577
RY2	37,560
RY3	58,988

Consolidated Edison Company of New York, Inc.
Case 16-E-0060 & Case 16-G-0061
Carrying Charge Rates

RY 1

	Electric AMI Plant	Gas AMI Plant
Pre Tax Overall Rate of Return	9.610%	9.610%
Composite Book Depreciation Rate	9.010%	8.784%
Total Carrying Charge Rate	18.620%	18.394%

RY 2

	Electric AMI Plant	Gas AMI Plant
Pre Tax Overall Rate of Return	9.590%	9.590%
Composite Book Depreciation Rate	8.345%	7.834%
Total Carrying Charge Rate	17.935%	17.424%

RY 3

	Electric AMI Plant	Gas AMI Plant
Pre Tax Overall Rate of Return	9.520%	9.520%
Composite Book Depreciation Rate	7.333%	6.482%
Total Carrying Charge Rate	16.853%	16.002%

Consolidated Edison Company of New York, Inc.
Examples Of Electric AMI Net Plant Overspend and Underspend Scenarios
(Thousands of Dollars Except Carrying Charges)

RY1*	Book Cost			Depreciation Reserve			Net Plant			Carrying Charge Computed 18.62%
	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	
Beg Balance	-	-	-	-	-	-	-	-	-	
Jan-17	9,724	10,724	(1,000)	-	-		9,724	10,724	(1,000)	
Feb-17	21,729	22,729	(1,000)	488	547	(59)	21,241	22,182	(941)	
Mar-17	33,734	34,734	(1,000)	1,121	1,180	(59)	32,613	33,554	(941)	
Apr-17	45,738	46,738	(1,000)	1,841	1,900	(59)	43,898	44,839	(941)	
May-17	57,743	58,743	(1,000)	2,647	2,706	(59)	55,096	56,037	(941)	
Jun-17	69,132	70,132	(1,000)	3,540	3,599	(59)	65,591	66,532	(941)	
Jul-17	81,136	82,136	(1,000)	4,519	4,578	(59)	76,617	77,559	(941)	
Aug-17	93,141	94,141	(1,000)	5,584	5,643	(59)	87,557	88,498	(941)	
Sep-17	105,146	106,146	(1,000)	6,736	6,794	(59)	98,410	99,351	(941)	
Oct-17	117,150	118,150	(1,000)	7,974	8,033	(59)	109,176	110,117	(941)	
Nov-17	129,155	130,155	(1,000)	9,299	9,358	(59)	119,856	120,797	(941)	
Dec-17	140,860	141,860	(1,000)	10,711	10,770	(59)	130,149	131,090	(941)	
Average	69,496	70,456	(958)	4,092	4,142	(51)	65,405	66,313	(907)	(168,861)

RY2**	Book Cost			Depreciation Reserve			Net Plant			Carrying Charge Computed 17.93%
	Actual	PSC/Rates	Variation PSC/Actual	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	
Dec-17	140,860	141,860	(1,000)	10,711	10,770	(59)	130,149	131,090	(941)	
Jan-18	156,410	154,910	1,500	12,208	12,266	(58)	144,202	142,644	1,558	
Feb-18	169,460	167,960	1,500	13,777	13,835	(58)	155,684	154,126	1,558	
Mar-18	182,510	181,010	1,500	15,418	15,476	(58)	167,092	165,534	1,558	
Apr-18	195,560	194,060	1,500	17,133	17,191	(58)	178,427	176,869	1,558	
May-18	208,611	207,111	1,500	18,921	18,979	(58)	189,689	188,131	1,558	
Jun-18	219,269	217,769	1,500	20,782	20,840	(58)	198,486	196,928	1,558	
Jul-18	232,319	230,819	1,500	22,710	22,768	(58)	209,609	208,051	1,558	
Aug-18	245,369	243,869	1,500	24,711	24,769	(58)	220,658	219,100	1,558	
Sep-18	258,419	256,919	1,500	26,785	26,843	(58)	231,634	230,076	1,558	
Oct-18	271,469	269,969	1,500	28,932	28,990	(58)	242,537	240,979	1,558	
Nov-18	284,519	283,019	1,500	31,152	31,210	(58)	253,367	251,809	1,558	
Dec-18	297,481	295,981	1,500	33,445	33,503	(58)	264,035	262,477	1,558	
Average	220,257	218,856	1,396	21,217	21,275	(58)	199,040	197,581	1,454	260,750
						****			Cumulative Carrying Charges	91,889

RY3***	Book Cost			Depreciation Reserve			Net Plant			Carrying Charge Computed 16.85%
	Actual	PSC/Rates	Variation PSC/Actual	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	
Dec-18	297,481	295,981	1,500	33,445	33,503	(58)	264,035	262,477	1,558	
Jan-19	315,680	314,180	1,500	35,929	35,871	58	279,750	278,308	1,442	
Feb-19	333,879	332,379	1,500	38,374	38,316	58	295,505	294,063	1,442	
Mar-19	352,078	350,578	1,500	40,894	40,836	58	311,184	309,742	1,442	
Apr-19	370,278	368,778	1,500	43,491	43,433	58	326,787	325,345	1,442	
May-19	388,477	386,977	1,500	46,164	46,106	58	342,313	340,871	1,442	
Jun-19	406,676	405,176	1,500	48,912	48,854	58	357,764	356,322	1,442	
Jul-19	424,875	423,375	1,500	51,737	51,679	58	373,138	371,696	1,442	
Aug-19	443,075	441,575	1,500	54,638	54,580	58	388,436	386,994	1,442	
Sep-19	461,274	459,774	1,500	57,616	57,558	58	403,658	402,216	1,442	
Oct-19	479,473	477,973	1,500	60,669	60,611	58	418,804	417,362	1,442	
Nov-19	497,673	496,173	1,500	63,799	63,741	58	433,874	432,432	1,442	
Dec-19	515,872	514,372	1,500	67,004	66,946	58	448,868	447,426	1,442	
Average	406,676	405,176	1,500	49,371	49,317	53	357,306	355,859	1,447	243,834
						****			Cumulative Carrying Charges	335,724

Note:
* RY1 - Scenario : Actual Net Plant Below Target Net Plant Reflected in Electric and Gas Rates
** RY2 - Scenario : Actual Net Plant Above Target Net Plant Reflected in Electric and Gas Rates
*** RY3 - Scenario : Actual Net Plant Above Target Net Plant Reflected in Electric and Gas Rates
**** The Company may be limited from accruing a full carrying charge to other operating revenues

Any regulatory asset or regulatory liability at the end of the Electric Rate Plan or Gas Rate Plan will not result in a debit or credit for disposition to the Company or to electric and/or gas customers, respectively. Such regulatory asset or regulatory liability may reverse over the remaining AMI project implementation period (currently projected to end in 2022) based on actual expenditures as compared to AMI costs reflected in rates established during the term(s) of future electric and/or gas rate plans. Any credit due electric and/or gas customers or debit due the Company will be determined upon project completion, after computing net plant associated with actual aggregate expenditures for both electric and gas to the net plant associated with the overall project cap of $1.285 billion. If at the completion of the project the actual net plant amount for a service is above the net plant target for that service, the Company will be able to defer carrying charges associated with the net plant overage for that service to the extent the capital expenditures associated with the AMI Deployment do not exceed the overall project capital cap of $1.285 billion.

Consolidated Edison Company of New York, Inc.
Examples Of Gas AMI Net Plant Overspend and Underspend Scenarios
(Thousands of Dollars Except Carrying Charges)

	Book Cost			Depreciation Reserve			Net Plant			
RY1*	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Carrying Charge Computed 18.39%
Beg Balance	-	-	-	-	-	-	-	-	-	
Jan-17	1,330	2,330	(1,000)	-	-		1,330	2,330	(1,000)	
Feb-17	3,923	4,923	(1,000)	56	112	(56)	3,866	4,810	(944)	
Mar-17	6,515	7,515	(1,000)	186	242	(56)	6,329	7,273	(944)	
Apr-17	9,107	10,107	(1,000)	334	390	(56)	8,774	9,718	(944)	
May-17	11,700	12,700	(1,000)	499	555	(56)	11,200	12,144	(944)	
Jun-17	14,083	15,083	(1,000)	683	739	(56)	13,401	14,345	(944)	
Jul-17	16,676	17,676	(1,000)	884	939	(56)	15,792	16,736	(944)	
Aug-17	19,268	20,268	(1,000)	1,102	1,158	(56)	18,166	19,110	(944)	
Sep-17	21,860	22,860	(1,000)	1,339	1,395	(56)	20,522	21,466	(944)	
Oct-17	24,453	25,453	(1,000)	1,593	1,649	(56)	22,860	23,804	(944)	
Nov-17	27,045	28,045	(1,000)	1,865	1,921	(56)	25,180	26,124	(944)	
Dec-17	29,577	30,577	(1,000)	2,156	2,211	(56)	27,422	28,366	(944)	
Average	14,229	15,188	(958)	802	850	(49)	13,428	14,339	(909)	(167,275)

	Book Cost			Depreciation Reserve			Net Plant			
RY2**	Actual	PSC/Rates	Variation PSC/Actual	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Carrying Charge Computed 17.42%
Dec-17	29,577	30,577	(1,000)	2,156	2,211	(56)	27,422	28,366	(944)	
Jan-18	35,233	33,733	1,500	2,461	2,519	(58)	32,772	31,214	1,558	
Feb-18	38,389	36,889	1,500	2,784	2,842	(58)	35,605	34,047	1,558	
Mar-18	41,544	40,044	1,500	3,122	3,180	(58)	38,423	36,865	1,558	
Apr-18	44,700	43,200	1,500	3,475	3,533	(58)	41,225	39,667	1,558	
May-18	47,855	46,355	1,500	3,843	3,901	(58)	44,012	42,454	1,558	
Jun-18	50,188	48,688	1,500	4,227	4,285	(58)	45,962	44,404	1,558	
Jul-18	53,344	51,844	1,500	4,624	4,682	(58)	48,720	47,162	1,558	
Aug-18	56,499	54,999	1,500	5,036	5,094	(58)	51,463	49,905	1,558	
Sep-18	59,655	58,155	1,500	5,464	5,522	(58)	54,191	52,633	1,558	
Oct-18	62,810	61,310	1,500	5,907	5,965	(58)	56,903	55,345	1,558	
Nov-18	65,966	64,466	1,500	6,365	6,423	(58)	59,601	58,043	1,558	
Dec-18	69,637	68,137	1,500	6,839	6,897	(58)	62,798	61,240	1,558	
Average	50,483	49,082	1,396	4,317	4,375	(58)	46,166	44,707	1,454	253,304
						****			Cumulative Carrying Charges	86,028

	Book Cost			Depreciation Reserve			Net Plant			
RY3***	Actual	PSC/Rates	Variation PSC/Actual	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Carrying Charge Computed 16.00%
Dec-18	69,637	68,137	1,500	6,839	6,897	(58)	62,798	61,240	1,558	
Jan-19	74,553	73,053	1,500	7,445	7,387	58	67,108	65,666	1,442	
Feb-19	79,469	77,969	1,500	7,952	7,894	58	71,517	70,075	1,442	
Mar-19	84,384	82,884	1,500	8,475	8,417	58	75,910	74,468	1,442	
Apr-19	89,300	87,800	1,500	9,014	8,956	58	80,286	78,844	1,442	
May-19	94,216	92,716	1,500	9,570	9,512	58	84,646	83,204	1,442	
Jun-19	99,131	97,631	1,500	10,142	10,084	58	88,989	87,547	1,442	
Jul-19	104,047	102,547	1,500	10,731	10,673	58	93,316	91,874	1,442	
Aug-19	108,963	107,463	1,500	11,336	11,278	58	97,627	96,185	1,442	
Sep-19	113,878	112,378	1,500	11,957	11,899	58	101,921	100,479	1,442	
Oct-19	118,794	117,294	1,500	12,595	12,537	58	106,199	104,757	1,442	
Nov-19	123,710	122,210	1,500	13,249	13,191	58	110,460	109,018	1,442	
Dec-19	128,625	127,125	1,500	13,920	13,862	58	114,705	113,263	1,442	
Average	99,131	97,631	1,500	10,237	10,184	53	88,894	87,447	1,447	231,516
						****			Cumulative Carrying Charges	317,545

Note:
* RY1 - Scenario : Actual Net Plant Below Target Net Plant Reflected in Electric and Gas Rates
** RY2 - Scenario : Actual Net Plant Above Target Net Plant Reflected in Electric and Gas Rates
*** RY3 - Scenario : Actual Net Plant Above Target Net Plant Reflected in Electric and Gas Rates
**** The Company may be limited from accruing a full carrying charge to other operating revenues

Any regulatory asset or regulatory liability at the end of the Electric Rate Plan or Gas Rate Plan will not result in a debit or credit for disposition to the Company or to electric and/or gas customers, respectively. Such regulatory asset or regulatory liability may reverse over the remaining AMI project implementation period (currently projected to end in 2022) based on actual expenditures as compared to AMI costs reflected in rates established during the term(s) of future electric and/or gas rate plans. Any credit due electric and/or gas customers or debit due the Company will be determined upon project completion, after computing net plant associated with actual aggregate expenditures for both electric and gas to the net plant associated with the overall project cap of $1.285 billion. If at the completion of the project the actual net plant amount for a service is above the net plant target for that service, the Company will be able to defer carrying charges associated with the net plant overage for that service to the extent the capital expenditures associated with the AMI Deployment do not exceed the overall project capital cap of $1.285 billion.

Appendix 11 -- Book Depreciation Rates

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

**Average Service Lives, Net Salvage,
Annual Depreciation Rates and Life Tables**

PSC Acct	Company Account	Average Service Life In Years	Net Salvage %	Annual Rate %	Life Table No.	
	Electric Plant in Service					
	Production Plant - Steam Production					
311	311000 E Structures & Improvements	95	(25)	3.13	h 0.75	(F)
312	312000 E Boiler Plant Equipment	65	(25)	3.56	h 1.00	(F)
314	314000 E Turbogenerator	50	(25)	3.42	h 1.75	(F)
315	315000 E Accessory Electric Eq	45	(25)	3.89	h 1.50	(F)
316	316000 E Misc Power Plant Equipment	50	(25)	3.83	h 1.00	(F)
	Production Plant - Other Production					
341	341000 E Structures & Improvements	95	(10)	4.25	h 1.00	(F)
342	342000 E Fuel Holders	70	(10)	3.30	h 1.50	(F)
344	344000 E Generators	55	(10)	5.15	h 2.50	(F)
345	345000 E Accessory Electric Eq	60	(10)	4.87	h 2.00	(F)
348	348000 E Storage Equipment	15	0	6.67	h 4.00	
	Transmission Plant					
303	303090 E Cap Sftw for Electric Tran	5	-	20.00	Amort	(D)
351	351000 E Storage Equipment	15	0	6.67	h 4.00	
352	352000 E Structures & Improvements	80	(40)	1.75	h 2.50	
353	353000 E Station Equipment	50	(35)	2.70	h 1.75	
354	354000 E Towers & Fixtures	65	(40)	2.15	h 4.00	
356	356000 E O/H Conductors & Devices	50	(35)	2.70	h 2.50	
357	Underground Conduit					
	357000 E UG Conduit	70	(15)	1.64	h 4.00	
	357200 E U/G Conduit - Manhattan/Br	70	(15)	1.64	h 4.00	
358	358000 E U/G Conductors & Devices	60	(15)	1.92	h 2.75	

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Average Service Lives, Net Salvage,
Annual Depreciation Rates and Life Tables

PSC Acct	Company Account	Average Service Life In Years	Net Salvage %	Annual Rate %	Life Table No.	
	Electric Plant in Service					
	Distribution Plant					
360	360000 E Land & LR - Easements/Lshl	50	-	2.00	Amort	
361	361000 E Structures & Improvements	52	(45)	2.79	h 2.50	
362	362000 E Station Equipment	50	(30)	2.60	h 2.00	
	362010 E Station Equipment BQDM DC Link	10		10.00		
363	363000 E Energy Storage Equipment	15	0	6.67	h 4.00	
	363010 E Energy Storage Equipment BQDM Brownsville Proj.	10		10.00		
364	364000 E Poles, Towers and Fixtures	65	(105)	3.15	h 1.00	
303	Capitalized Software					
	303010 E Cap Sftw for Electric Dist	5	-	20.00	Amort	(D)
	303015 E Cap Sftw for Electric Dist (WMS)	15	-	6.67	Amort	(D)
365	365000 E O/H Conductors & Devices	70	(60)	2.29	h 1.00	
366	Underground Conduit					
	366000 E U/G Conduit	80	(45)	1.81	h 2.00	
	366100 E U/G Conduit - Manhattan/Br	80	(45)	1.81	h 2.00	
	366010 E U/G Conduit -BQDM	10		10.00		
367	367000 E U/G Conductors & Devices	50	(75)	3.50	h 0.75	
	367010 E U/G Conductors & Devices BQDM DC link	10		10.00		
368	Line Transformers					
	368000 E Line Trnsf O/H	35	(20)	3.43	h 1.00	
	368100 E Line Trnsf U/G	35	(20)	3.43	h 1.50	
	368110 E Transformers BQDM	10		10.00		
369	Services					
	369100 E Services - O/H	70	(180)	4.00	h 1.00	
	369200 E Services - U/G	80	(150)	3.13	h 1.00	
370	Meters					
	370100 E Meters - Purchases (Electro-Mechanical)	35	(5)	3.00	h 0.75	
	370110 E Meters - Purchases (Solid-State)	20	(5)	5.25	h 0.75	
370	Meters Installations					
	370200 E Meters - Install (Electro-Mechanical)	35	-	2.86	h 0.75	
	370210 E Meters - Install (Solid-State)	20	-	5.00	h 0.75	
	370310 E Meters - Install (AMI)	20	-	5.00	h 0.75	
371	371000 E Inst on Cust Prem	65	(5)	1.62	h 1.25	
373	Street Lighting and Signal Systems					
	373100 E St Lt & Sig Sys - O/H	55	(105)	3.73	h 0.75	
	373200 E St Lt & Sig Sys - U/G	75	(100)	2.67	h 1.00	
	Electric Plant Held for Future Use					
	Transmission Plant					
357	357300 E UG Conduit Fu	-		-	-	

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

**Average Service Lives, Net Salvage,
Annual Depreciation Rates and Life Tables**

PSC Acct	Company Account	Average Service Life In Years	Net Salvage %	Annual Rate %	Life Table No.	
	Gas Plant in Service					
	Natural Gas Storage Plant					
	Other Storage Plant					
361	361000 G Str & Impr - Liquefied Sto	100	(15)	3.55	h 1.00	(F)
362	362100 G Gas Holders - Liq Stg	80	(15)	2.41	h 3.50	(F)
363	363000 G Purification Equipment	70	(15)	2.53	h 3.00	(F)
363.1	363100 G Liquefaction Equipment	70	(15)	3.41	h 4.00	(F)
363.2	363200 G Vaporizing Equipment	40	(15)	4.46	h 3.50	(F)
363.3	363300 G Compr Eq - Liq Stg	60	(15)	3.45	h 2.75	(F)
363.4	363400 G Meas & Reg Eq.- Liq Stg	30	(15)	4.44	h 2.50	(F)
363.5	363500 G Other Eq - Liq Stg	70	(15)	2.96	h 1.50	(F)
	Transmission Plant					
366	366000 G Structures & Improvements	40	(40)	3.50	h 2.00	
367	Mains					
	367100 G Gas Mains- All Other	85	(75)	2.06	h 2.75	(B)
	367200 G Gas Mains - Cast Iron	70	(100)	2.86	h 1.75	
	367300 G Gas Mains - Tunnel	100	(85)	1.85	h 5.00	
368	368000 G Compressor Station Eq	30	(10)	3.67	h 3.50	
369	369000 G Meas & Reg Stn Eq	50	(40)	2.80	h 1.50	
	Distribution Plant					
376	Mains					
	376120 G Gas Mains - All Other	85	(75)	2.06	h 2.75	(B)
	376110 G Gas Mains - Cast Iron	70	(100)	2.86	h 1.75	(B)
380	380100 G Gas Services - All Other	65	(45)	2.23	h 1.25	(B)
381	381000 G Meters - Purchases	40	(10)	2.75	h 1.50	
382	382000 G Meters - Installations	40	-	2.50	h 1.50	
	382100 AMI G Meters - Installations	20	-	5.00	h 1.50	
383	383000 G House Reg - Pch	42	0	2.38	h 2.25	
384	384000 G House Reg - Inst	42	0	2.38	h 2.25	
303	303020 G Cap Sftw for Gas 5 yr	5	-	20.00	Amort	(D)

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

**Average Service Lives, Net Salvage,
Annual Depreciation Rates and Life Tables**

PSC Acct	Company Account	Average Service Life In Years	Net Salvage %	Annual Rate %	Life Table No.	
	Steam Plant in Service					
	Production Plant					
	(Excluding ERRP & 74th St (transferred from Electric)					
310	**Land and Land Rights - Leaseholds**					
	310200 S Land & LR - Lshlds-59th St					**(A) (C)**
	310300 S Land & LR - Lshlds-74th St					**(A) (C)**
311	**311100 S Structures & Improvements**	35	(60)	4.57%	h 0.00	**(C)**
312	**312100 S Boiler Plant Equipment**	30	(30)	4.33%	h 0.25	**(C)**
315	**315100 S Accessory Power Equipment**	35	(25)	3.57%	h 0.25	**(C)**
316	**316100 S Miscellaneous Station Eq**	40	(10)	2.75%	h 1.50	**(C)**
	Production Plant					
	74th St (transferred from Electric)					
310	**310400 S Land & LR-Lshlds-74St FR**					
311	**311200 S Str & Impr-74th St Fully R**	-	-	1.25%	-	
312	**312200 S Boiler Plant Eq-74th St Fu**	-	-	1.43%	-	
315	**315200 S Acc Power Eq-74th St Fully**	-	-	0.71%	-	
316	**316200 S Misc Station Equipment-74t**	-	-	0.22%	-	
	Production Plant & Distribution Plant - ERRP					
311	**311300 S Str & Impr-ERRP**	35	(60)	4.57%	h 0.00	
312	**312300 S Boiler Plant Eq-ERRP**	30	(30)	4.33%	h 2.50	
315	**315300 S Accessory Power Eq-ERRP**	35	(25)	3.57%	h 0.25	
316	**316300 S Misc Station Equipment-ERR**	40	(10)	2.75%	h 1.50	
353	**353020 S Steam Mains-ERRP**	80	(75)	2.19%	h 0.25	
353	**353120 S Stm Mains - Desuperheating**	45	(45)	3.22%	h 1.25	
	Distribution Plant (Excluding ERRP)					
303	**303040 S Cap Sftw for Steam 5 yr**	5	-	20.00%	Amort	**(D)**
351	**351000 S Structures & Improvements**	50	-	2.00%	h 5.00	
353	**Mains**					
	353010 S Steam Mains	80	(75)	2.19%	h 0.25	
	353110 S Stm Mains - Desuperheating	45	(45)	3.22%	h 1.25	
359	**359000 S Services**	60	(50)	2.50%	h 0.00	
360	**360000 S Meter - Purchases**	35	(5)	3.00%	h 1.75	
361	**361000 S Acc Eq on Cust Prem**	60	(15)	1.92%	h 0.50	
362	**362000 S Inst of Meter & Acc Eq**	60	(20)	2.00%	h 0.75	

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Average Service Lives, Net Salvage, Annual Depreciation Rates and Life Tables

PSC Acct	Company Account	Average Service Life In Years	Net Salvage %	Annual Rate %	Life Table No.	
	Common Utility Plant in Service					
	Intangible Plant					
303	Miscellaneous Intangible Plant					
	303060 C Cap Sftw for C Plant 5 yr	5	-	20.00	AMORT.	(D)
	303070 C Cap Sftw for C Plant 10 yr	10	-	10.00	AMORT.	(D)
	303080 C Cap Sftw for C Plant 15 yr					
	HR Payroll	15	-	6.67	AMORT.	(D)
	Project One	15	-	6.67	AMORT.	(D)
	PowerPlant	15	-	6.67	AMORT.	(D)
	303900 C AMI software	20		5.00	AMORT.	(D)
	General Plant					
390	Structures and Improvements					
	390100 C Struct & Improv TRC A	55	(40)	2.55	h 0.75	
	390200 C Struct & Improv TRC B	55	(40)	2.55	h 0.75	
	390300 C Struct & Improv TRC C	55	(40)	2.55	h 0.75	
391	Office Furniture and Equipement					
	Electronic Data Processing Equipment					
	391700 C OFE. - EDP Eq	8	5	11.88	-	(E)
	391720 C OFE. - EDP Eq - ERRP	8	5	11.88	-	(E)
	Other Office Furniture and Equipment					
	391100 C OFE. - Furniture	18	-	5.56	-	(E)
	391200 C OFE. - Office Machines	18	-	5.56	-	(E)
392	Transportation Equipment					
	392100 C Tr. Eq. - Automobiles	8	10	11.25	-	(E)
	392200 C Tr. Eq. - Light Trucks	8	10	11.25	-	(E)
	392300 C Tr. Eq. - Heavy Trucks	8	10	11.25	-	(E)
	392400 C Tr. Eq. - Tr. & Mtd.Equip.	8	10	11.25	-	(E)
	392500 C Tr. Eq. - Buses	8	10	11.25	-	(E)
	392600 C Tr. Eq. - Tractors	8	10	11.25	-	(E)
393	393000 C Stores Equipment	20	5	4.75	-	(E)
394	394000 C Tools, Shop & Garage Eq	18	5	5.28	-	(E)
395	395000 C Laboratory Equipment	20	-	5.00	-	(E)
396	396000 C Power Operated Equipment	12	10	7.50	-	(E)
397	397000 C Comm. Eqment	15	-	6.67	-	(E)
	397100 C AMI Comm. Eqment	15	-	6.67	0	(E)
398	398000 C Misc. Equip.	20	-	5.00	-	(E)
	Nonutility Property Plant in Service					
121	304700 NU Nonutility Telecom	10	0	10.00	-	

NOTES
(A) Remaining life amortization by location.
(B) Gas Plant in Service other than Interruptible Gas Plant.
(C) Other than the fully recovered investment at the 74th Street Station.
(D) Amortization in accordance with the Software Accounting Guideline.
(E) Effective 1/1/95, investment in account is being amortized in accordance with the method specified in Case No. 93-M-1098.
(F) Life span method is used. Curve shown is interim survivor curve.

Appendix 12 -- Earnings Sharing Partial Year

Consolidated Edison Company of New York, Inc.
Electric Case 16-E-0060
Earnings Sharing Partial Year
During Stub Period Starting January 1, 2020
(000's)

Assumption: CECONY Delays Filing for New Rates for Six Months

Month / Year	Electric Net Income	
January 31, 2020	$ 93,000	
February 28, 2020	94,000	
March 31, 2020	78,000	
April 30, 2020	86,000	
May 31, 2020	118,000	
June 30, 2020	170,000	
Total		$ 639,000

	Electric Rate Base	
Rate Base as of December 31, 2019	$ 20,276,680	
Rate Base as of June 30, 2020	20,650,249	
Total	40,926,929	
Divided by Two	2	
Average Rate Base During Stub Period	$ 20,463,464	
x Ratio of operating income for the six months ended June 2015 to operating income for the 12 months ended December 2015	46.9%	
Rate Base Subject to Earnings Test		$ 9,587,000
Overall Rate of Return ($ 639,000 / $ 9,587,000)		6.67%
Return on Equity (Page 2)	8.88%	
Earnings Sharing Threshold	9.50%	
Earnings Above / (Under) Threshold	-0.62%	
Equity Earnings Base ($ 9,587,000 x 48.00%)	$ 4,601,760	
Equity Earnings Above / (Under) Target ($ 4,601,760 x -0.62%)	$ (28,610)	

Consolidated Edison Company of New York, Inc.
Electric Case 16-E-0060
Capital Structure & Cost of Money
During Stub Period Starting January 1, 2020

	Capital Structure %	Cost Rate %	Cost of Capital %
Long Term Debt	50.55%	4.74%	2.40%
Customer Deposits	1.45%	0.85%	0.01%
Total Debt	52.00%		2.41%
Common Equity	48.00%	8.88%	4.26%
Total	100.00%		6.67%

Consolidated Edison Company of New York, Inc.
Gas Case 16-G-0061
Earnings Sharing Partial Year
During Stub Period Starting January 1, 2020
(000's)

Assumption: CECONY Delays Filing for New Rates for Six Months

Month / Year	Gas Net Income	
January 31, 2020	$ 85,000	
February 28, 2020	85,000	
March 31, 2020	70,000	
April 30, 2020	41,000	
May 31, 2020	21,000	
June 30, 2020	5,000	
Total		$ 307,000

	Gas Rate Base	
Rate Base as of December 31, 2020	$ 6,005,011	
Rate Base as of June 30, 2021	6,310,174	
Total	12,315,185	
Divided by Two	2	
Average Rate Base During Stub Period	$ 6,157,593	
x Ratio of operating income for the six months ended June 2015 to operating income for the 12 months ended December 2015	76.0%	
Rate Base Subject to Earnings Test		$ 4,682,000
Overall Rate of Return ($ 307,000 / $ 4,682,000)		6.56%
Return on Equity (Page 2)	8.65%	
Earnings Sharing Threshold	9.50%	
Earnings Above / (Under) Threshold	-0.85%	
Equity Earnings Base ($ 4,682,000 x 48.00%)	$ 2,247,360	
Equity Earnings Above / (Under) Target ($ 2,247,360 x -0.85%)	$ (19,120)	

Consolidated Edison Company of New York, Inc.
Gas Case 16-G-0061
Capital Structure & Cost of Money
During Stub Period Starting January 1, 2020

	Capital Structure %	Cost Rate %	Cost of Capital %
Long Term Debt	50.55%	4.74%	2.40%
Customer Deposits	1.45%	0.85%	0.01%
Total Debt	52.00%		2.41%
Common Equity	48.00%	8.65%	4.15%
Total	100.00%		6.56%

Appendix 13 -- Common Allocation Factors

Consolidated Edison Company of New York, Inc.

Cases 16-E-0060, 16-G-0061

Common Allocation Factors

	Electric	Gas	Steam
Administrative & General Expenses (FERCs 9200 - 9350)	77.60%	15.95%	6.45%
Customer Accounting Expenses (FERCs 9010 - 9160)	84.00%	16.00%	-
Taxes Other than Income Taxes/Property Taxes	77.60%	15.95%	6.45%
Common Plant (including Property Taxes on Common Plant)	83.00%	17.00%	-
Common M&S	77.00%	17.00%	6.00%

Appendix 14 -- Electric Service Reliability Performance Mechanism

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Electric Service Reliability Performance Mechanism

Operation of Mechanism

This Electric Service Reliability Performance Mechanism ("reliability mechanism") will go into effect for Consolidated Edison Company of New York, Inc. (Con Edison or the Company) on January 1, 2017 and will remain in effect until reset by the Commission. The measurement periods for the reliability mechanism metrics are stated in the description of each metric below.

This reliability mechanism establishes seven performance metrics:

(a) threshold standards, consisting of system-wide performance targets;

(b) a major outage metric;

(c) a remote monitoring system metric;

(d) a program standard for repairs to damaged poles;

(e) a program standard for the removal of temporary shunts;

(f) a program standard for the repair of "no current" street lights, and traffic signals; and

(g) a program standard for over-duty circuit breakers.

All revenue adjustments related to this reliability mechanism will come from shareholder funds and will be deferred for the benefit of ratepayers.

Summary of Mechanism

	Requirement for Revenue Adjustment	**Annual Revenue Adjustment Exposure (millions)**
Threshold Standards		
Network Outage Duration	Con Ed Performance > 4.70	$5.00
CAIDI[1]P (radial)	Con Ed Performance > 2.04	$5.00
Network Outages per 1000 customers	Con Ed Performance > 2.5[2]	$4.00
Summer Open Automatics (network)	Con Ed Performance > 330	$1.00
SAIFI[3] (radial)	Con Ed Performance > 0.495	$5.00
Major Outages		
Network	The interruption of service to 15 percent or more of the customers in any network for a period of three hours or more.	$5.0 to $15.0/event
Radial	One event that results in the sustained interruption of service to 70,000 customers for three hours or more.	$10.0/event
Maximum Exposure		$30.00
Remote Monitoring System Reporting		
Network	Failure by the Company to achieve 90 percent reporting rate for the Remote Monitoring System in each network during the last month of each quarter.	$10.0/network
Maximum Exposure		$50.00

[1] CAIDI – Customer Average Interruption Duration Index. The average interruption duration time (customers-hours interrupted) for those customers that experience an interruption during the year.

[2] The customer count as of December 31 of the preceding year was used in calculating historical performance that formed the basis of this target and will be used in measuring the Company's actual performance during each calendar year.

[3] SAIFI – System Average Interruption Frequency Index. It is the average number of times that a customer is interrupted per 1,000 customers served during the year.

	Requirement for Revenue Adjustment	**Annual Revenue Adjustment Exposure (millions)**
Program Standards		
Pole Repair	For all “Damaged Poles” and “Double Damaged Poles” that come into existence on or after 1/1/17, repairs not made within 30 days from the date the Company became aware of the “Damaged Pole” or “Double Damaged Pole” for at least 90% of these new “Damaged Poles” and “Double Damaged Poles”.	$3.00
Shunt Removal	For all shunts that come into existence on or after 1/1/17, permanent repairs not made for at least 90% of these new cases within 90 days during the winter months, which are defined for purposes of this metric as January, February, March, April, November, and December, and at least 90% of these cases within 60 days during the remaining six months, May through October that is defined as the summer months.	Winter: $1.5 Summer: $1.5
No Current Street Lights and Traffic Signals	For all no currents that come into existence on or after 1/1/17, permanent repairs not made for at least 90% of these new cases within 90 days during the winter months, which are defined for purposes of this metric as January, February, March, April, November, and December, and at least 80% of these new cases within 45 days during the remaining six months, May through October that is defined as the summer months.	Winter: $1.5 Summer: $1.5
Over-Duty Circuit Breakers	If Con Edison does not replace at least 50 over-duty circuit breakers in each calendar year and at least 180 over the three- year cycle.	$0.1 Per Breaker $1.5 annually
	Revenue adjustment capped at $1.5 million per year for not meeting annual target. At the end of the three-year cycle, there will be an additional revenue adjustment of $0.1 million per breaker, capped at $3.0 million, if the cumulative three-year cycle target is not met.	$1.5 annual $3.0 cummulative per three-year cycle
Maximum Exposure		$7.5
Total Revenue Adjustment Exposure: $110.5 for RY1 $110.5 for RY2 $115.0 for RY3		

Exclusions

The following exclusions will be applicable to operating performance under this reliability mechanism.

(a) Any outages resulting from a major storm, as defined in 16 NYCRR Part 97 (for at least 10% of the customers interrupted within an operating area or customers out of service for at least 24 hours), except as otherwise noted; this includes secondary underground network interruptions that occur in an operating area during winter snow/ice events that meet the 16 NYCRR Part 97 definition (10%/24 hour rule) and includes interruptions to customers in secondary network areas who are supplied via overhead lines connected to an underground network system.

(b) Heat-related outages are not a major storm. However, the Company may petition the Commission for an exemption for an outage if the Company can prove that such outage, whether heat-related or not, was beyond the Company's control, taking into account all facts and circumstances.

(c) Any incident resulting from a strike or a catastrophic event beyond the control of the Company, including but not limited to plane crash, water main break, or natural disasters (*e.g.*, hurricanes, floods, earthquakes).

(d) Any incident where problems beyond the Company's control involving generation or the bulk transmission system is the key factor in the outage, including, but not limited to, NYISO mandated load shedding. This criterion is not intended to exclude incidents that occur as a result of unsatisfactory performance by the Company.

Reporting

The Company will prepare an annual report on its performance under this reliability mechanism. The annual report will be filed by March 31st of each Rate Year with the Secretary to the Commission; Director of the Office of Electric, Gas, and Water; and Chief of Electric Distribution Systems. Copies of the annual report will be simultaneously provided to the New York City Department of Transportation ("NYCDOT") Deputy Commissioner of Traffic Operations, the NYCDOT Director of Street Lighting, the Westchester County First Deputy Commissioner of Public Works, and the President of the Utility Workers Union of America, Local 1-2.

The reports will state the:

(a) Company's annual system-wide performance under the Threshold Standards and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment;

(b) Company's performance under the Major Outage metric and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment;

(c) Company's performance under the Remote Monitoring System metric and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment;

(d) Company's performance under the Program Standards applicable during the period and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment; and

(e) Provide adequate support for all exclusions.

Within 45 days of any event that meets the Major Outage criteria, the Company will file an interim report on the event, containing, among other things, information pertinent to determining whether a revenue adjustment for the event is applicable. Any requests for exclusion must be made in the interim report.

Threshold Standards

In Cases 90-E-1119, 95-E-0165, 96-E-0979, and 02-E-1240, the Commission adopted standards establishing minimum performance for frequency and duration of service interruption for network and radial systems. Under these standards, the frequency of service interruptions is measured by the System Average Interruption Frequency Index ("SAIFI"), and the duration of service interruptions is measured by the Customer Average Interruption Duration Index ("CAIDI").

The system-wide performance targets used for purposes of the threshold standards metric are as set forth below. The measurement periods for the threshold standards are successive 12-month periods ending December 31 of each year. During each annual measurement period, Con Edison's year-end SAIFI index for its entire radial system will be measured against the respective SAIFI system-wide performance target. During each annual measurement period, Con Edison's year-end weighted average CAIDI index for its entire radial system will be measured against the respective CAIDI system-wide performance target.

The network duration target will be a temporary replacement for network CAIDI. The measurement period for network duration are successive 12-month periods ending December 31 of each year. During each annual measurement period, Con Edison's year- end duration for its entire network system will be measured against the respective duration target.

The network interruption and summer feeder open-auto targets will be a temporary replacement for network SAIFI. The measurement period for network interruption are successive 12-month periods ending December 31 of each year. During each annual measurement period, Con Edison's year-end number of interruptions for its entire network system will be measured against the respective interruption target. The measurement period for summer feeder open-auto includes the months of June, July, and August of each year. During each annual measurement period, Con Edison's summer-end feeder open-auto rate for its network system will be measured against the respective feeder open-auto target.

The Company's annual performance in maintaining reliability must meet or be better than the SAIFI and CAIDI system-wide performance, Network Duration, Network Interruption, and Summer Feeder Open-Auto targets. A total of $20 million is at risk for performance not meeting these targets.

(a) Radial – CAIDI

A total of $5 million per year is at risk for customer interruption duration performance, as follows:

	Threshold Target (hours)	Revenue Adjustment (millions)
Radial CAIDI	2.04	$5

(b) Network Outage Duration

A total of $5 million per year is at risk for network outage duration performance, as follows:

	Threshold Target (hours)	Revenue Adjustment (millions)
Network outage duration	4.7	$5

(c) Radial – SAIFI

A total of $5 million per year is at risk for customer interruption frequency performance, as follows:

	Threshold Target	Revenue Adjustment (millions)
Radial SAIFI	0.495	$5

(c) Network Outage

A total of $4 million per year is at risk for network outage performance, as follows:

	Threshold Target	Revenue Adjustment (millions)
Network Outages per 1000 customers	2.5	$ 4

(d) Summer Feeder Open-Auto Target

A total of $1 million per year is at risk for summer network feeder open- auto performance, as follows:

	Threshold Target	Revenue Adjustment (millions)
Summer Network Feeder Open-Auto	330	$ 1

<u>Major Outages</u>

For purposes of this metric, a "major outage" event in a network system is defined as the interruption of service to 15 percent or more of the customers in any network for a period of three hours or more. If the Company creates any new second contingency networks during the Electric Rate Plan, those networks will be covered by this metric. A radial system interruption event is defined as one event that results in the sustained interruption of service to 70,000 customers for three hours or more.

Any single occurrence that results in multiple network or radial system interruption events will result in only one revenue adjustment being assessed. An example is the loss of an area substation that shuts down two or more networks or a combination of network and radial system load.

This single occurrence exception will not apply if each Major Outage that takes place during any single occurrence results from separate and distinct causes. For example, if there are two network shutdowns during a single heat wave, and each network shutdown results from failures on that particular network that were not beyond the Company's control, the single occurrence exception would not apply and two network shutdowns will be considered to have occurred.

In addition, Con Edison shall not be subject to a revenue adjustment when the 15% threshold is met due to an outage that is confined to one building within a network. The Company can petition the Commission for exemption on a case-by-case basis, of outages affecting more than one building that are, nevertheless, small scale and do not warrant classification as a Major Outage.

To avoid multiple revenue adjustments for the same operating performance problem or occurrence, interruptions and customer hours of interruption associated with Major Outage revenue adjustments will be excluded from the appropriate year-end system-wide performance calculations, except as noted.

The Company will be subject to a revenue adjustment based on the outage duration. Con Edison will be subject to a maximum revenue adjustment of $30 million. After the $30 million cap has been reached, the effect of the major outage will be included in the system-wide performance measurements. The revenue adjustment structure is as follows:

(a) Network Major Outage

Network Outage Duration	15% or More of Network Customers
3 to 6 hours	$5 million
> 6 hours to 12 hours	$10 million
> 12 hours	$15 million

(b) Radial Major Outage

A revenue adjustment of $10 million is at risk for each radial major outage.

Remote Monitoring System

For each network, except upon the occurrence of extraordinary system conditions, the Company will have 90% of its Remote Monitoring System units reporting properly in each network. Failure by the Company to achieve the target level for the Remote Monitoring System will result in a revenue adjustment of $10 million per network per measurement interval with an annual cap of $50 million.

Where the Company can demonstrate that extraordinary circumstances prevented it from achieving the target level, those circumstances will be factored in measuring the Company's compliance with the above requirement. The determination of whether extraordinary circumstances exist will be made on a case-by-case basis and will be based on the particular facts and circumstances presented.

The Company will be required to submit on a quarterly basis, the RMS reporting rate per network during the last month of each quarter that commenced June 30, 2008.
This mechanism is an interim standard, with the intent of adopting a target level of 95% for each network when such a standard is found to be reasonable.

Program Standards

(a) Pole Repair

i) Definitions

1. “Damaged Poles” are poles damaged by storm conditions, vehicle contact, or other circumstances, and that support existing equipment

with temporary external bracing while not posing an immediate threat to the safety of the public or the distribution system.

2. "Double Damaged Poles" are poles damaged by storm conditions, vehicle contact, or other circumstances, and that are not capable of supporting existing equipment. In each of these cases, a new pole is installed next to the damaged pole and is braced to the damaged pole to safely support the damaged pole until the Company transfers equipment to the new pole.

3. "Repair," for purposes of this program standard, means transferring Company facilities to a new pole, and removing or "topping" the "damaged" pole.

ii) Performance Requirements

The Company will strive to repair all "Damaged Poles" and "Double Damaged Poles" in a timely manner. For all "Damaged Poles" and "Double Damaged Poles" that are in existence as of December 31, 2016, Con Edison will make permanent repairs and is subject to the revenue adjustment as required by the prior reliability mechanism. For all "Damaged Poles" and "Double Damaged Poles" that come into existence on or after January 1, 2017, Con Edison will make repairs within 30 days from the date the Company became aware of the "Damaged Pole" or "Double Damaged Pole" for at least 90% of these new "Damaged Poles" and "Double Damaged Poles". In the event the Company does not achieve the 90% within 30 days threshold for "Damaged Poles" and "Double Damaged Poles" that come into existence during or after the 2017 calendar year, it will incur a revenue adjustment of $3 million for such year.

Con Edison will make repairs to all "Damaged Poles" and "Double Damaged Poles" that come into existence on or after January 1, 2017 within six months of the dates the Company became aware of the damaged poles.

iii) Storm Exclusion

In an effort to permit the Company to utilize labor resources most effectively and facilitate the restoration of customers, the Company may utilize up to 60 days to make repairs on 90% of poles that become “Damaged Poles” and “Double Damaged Poles” during qualifying major storm events as defined in 16 NYCRR Part 97. Where the Company does not immediately make repairs on its poles, the Company shall ensure that each “Damaged Pole” and “Double Damaged Pole” is safe for public and vehicle access.

iv) Extraordinary Circumstances Exception

Where the Company can demonstrate that extraordinary circumstances prevent a repair within the 30-day, 60-day, or six month time frames, as appropriate, that non- repair will not be considered in measuring the Company's compliance with these requirements. The determination of whether extraordinary circumstances exist will be made on a case-by-case basis and will be based on the particular facts and circumstances presented.

v) Reporting

The Company’s annual report will: (i) report on "Damaged Poles" and "Double Damaged Poles" that come into existence from January 1 through December 31 of the prior year; (ii) provide the status of "Damaged Poles" and "Double Damaged Poles" that existed before January 1 of the prior year; (iii) identify the “Damaged Poles” and “Double Damaged Poles” that were not repaired; and, (iv) describe the extraordinary circumstances, if any, that prevented the repairs from being made. For (i) and (ii), the report will include, at a minimum, a listing of the damaged pole locations, the date the Company became aware of the problem at that location, and the date of the repair.

(b) Shunt Removal

It is not the purpose of this metric to require Con Edison to eliminate the use of temporary shunts; to the contrary, temporary shunts may be needed to restore electric service pending permanent repairs. In cases where temporary shunts are used, the Company will strive to remove them and make permanent repairs in a timely manner. It is Con Edison’s responsibility to identify all shunts installed by the Company.

i) Definitions

1. “Temporary Shunts” are cables installed by the Company to

temporarily maintain service continuity to a customer pending the permanent repair of a Company facility.

2. “Publicly Accessible Shunts” include street/sidewalk shunts and overhead to underground service shunts, including shunts to street lights, installed by the Company. Shunts installed within individual customer facilities, typically behind the customer's meter (called a “meter pan bridge”) or inside the customer's end line box (called a “service bridge”), that are not accessible to the general public are not covered by this metric.

3. “Permanent Repair” means that the condition necessitating the shunt has been fully remediated and service has been restored by the Company to the customer's facility before the shunt is removed.

ii) Performance Requirements

The Company will not remove any shunt that will have the effect of leaving a streetlight or traffic signal without power, except for exigent safety reasons,[4] until the condition giving rise to the need for the shunt has been completely repaired. Furthermore, it is Con Edison’s responsibility to repair the conditions on its system that required the use of the temporary shunts. For all shunts that are in existence as of December 31, 2016, Con Edison will make permanent repairs as required by the prior reliability mechanism. For all shunts that come into existence on or after January 1, 2017, Con Edison will make permanent repairs for at least 90% of these new cases within 90 days during the winter months, which are defined for purposes of this metric as January, February, March, April, November, and December, and at least 90% of these cases within 60 days during the remaining six months, May through October. Failure to reach the 90% threshold will result in the follow revenue adjustments:

[4] In such situations, and as appropriate, the Company either will replace its temporary shunt or effect the permanent repair.

Adjustment Level

Winter Months $1,500,000

May – October $1,500,000

Con Edison will make permanent repairs in all cases in which temporary shunts are installed on or after January 1, 2017 within six months of the dates the shunts are installed. The 60-day, 90-day and six month periods for making permanent repairs may be tolled in the event that, and for the period corresponding to, a third party (such as the municipal customer) must perform service at the site prior to, and as a precondition to, Con Edison's completion of work. The Company will be responsible for providing notice to the third party that its work is a precondition to the Company's work and for demonstrating the applicability of the tolling period.

iii) Extraordinary Circumstances Exception

Where the Company can demonstrate that extraordinary circumstances prevented a shunt repair within the 60-day, 90-day, or six month time frames, as appropriate, that non-repair will not be considered in measuring the Company's compliance with the above requirements. The determination of whether extraordinary circumstances exist will be made on a case-by-case basis and will be based on the particular facts and circumstances presented (*e.g.*, documentation demonstrating delays of more than 30 days in receiving street-opening permits from NYCDOT).

iv) Reporting

The Company's annual report will: (i) report on shunts installed from January 1 through December 31 of the prior year; (ii) provide the status of shunts installed before January 1 of the prior year; (iii) identify the shunt locations that were not permanently repaired within the 60-day, 90-day, and six month periods described above; and, (iv) describe the extraordinary circumstances, if any, that prevented the permanent repair of the shunts. For (i) and (ii), the report will include, at a minimum, a listing of the shunt locations, the date the Company became aware of the problem at each such location, the date the shunt was installed, the date of the permanent repair, and the date the shunt was removed.

(c) No Current Street Lights and Traffic Signals

i) Definitions

1. A “no current” is a location where Con Edison's electric service supplying power to municipal street lights or traffic signals is not working due to a failure of Con Edison's service to the customer facility point, and the date that a “no current” comes into existence is the date of the “stop tag” notifying Con Edison of the “no current” condition.
2. “Permanent repair” means that service has been permanently restored by the Company to the customer's facility point.

ii) Performance Requirements

The Company will strive to make permanent repairs to all no currents (including both street lights and traffic signals) in a timely manner.

For all no currents that are in existence as of December 31, 2016, Con Edison will make permanent repairs as required by the prior reliability mechanism. An exception will be made in situations in which the Company can demonstrate that it could not complete its repair due to work required to be undertaken by third parties. For all no currents that come into existence on or after January 1, 2017, Con Edison will make permanent repairs for at least 90% of these new cases within 90 days during the winter months, which are defined for purposes of this metric as January, February, March, April, November, and December, and at least 80% of these new cases within 45 days during the remaining six months, May through October. The Company's maximum exposure each year under this metric will be $3 million, as follows:

Adjustment Level
Winter Months $1,500,000
May – October $1,500,000

The Company will make permanent repairs to all no currents that come into existence on or after January 1, 2017 within six months of the dates they come into existence. The 45-day, 90-

day, and six month periods for making permanent repairs may be tolled in the event that, and for the period corresponding to, a third party (such as the municipal customer) must perform service at the site prior to, and as a precondition to, Con Edison's completion of work. The Company will be responsible for providing notice to the third party that its work is a precondition to the Company's work and for demonstrating the applicability of the tolling period.

iii) Extraordinary Circumstances Exception

Where the Company can demonstrate that extraordinary circumstances prevented a "no current" from being permanently repaired within the 45-day, 90-day, or six month time frames, as appropriate, that non-repair will not be considered in measuring the Company's compliance with the above requirements. The determination of whether extraordinary circumstances exist will be made on a case-by-case basis and will be based on the particular facts and circumstances presented (*e.g.*, documentation demonstrating delays of more than 30 days in receiving street opening permits from NYCDOT).

iv) Reporting

The Company's annual report will: (i) report on "no currents" that came into existence from January 1 through December 31 of the prior year; (ii) provide the status of "no currents" that existed before January 1 of the prior year; (iii) identify the "no current" locations that were not repaired within the 45-day, 90-day, and six month periods; and, (iv) describe the extraordinary circumstances, if any, that prevented the permanent repair of the "no currents." For (i) and (ii), the report will include, at a minimum, a listing of the "no current" locations, the date the Company became aware of the problem at each location, and the date of the permanent repair at each location.

(d). Over-Duty Circuit Breakers

Many of the Company's substations' circuit breakers are at or over their fault current capacity requiring customers with synchronous distributed generators sited in those networks to install customer side fault current mitigation where possible. Elimination of over-duty circuit breakers and taking other reasonable steps necessary to enable the installation of synchronous generators is a priority because of the significant interest in the use of DG to address a variety of concerns.

The Company will pay the cost of purchasing and installing fault current mitigation technology where an over-duty circuit breaker condition exists or will exist with the addition of DG to Con Edison's system up to a total of $3 million annually. The Company would cover the cost of only the least expensive, effective fault current mitigation device. The Company would be responsible for replacing this device when still needed due to an over-duty circuit breaker condition, including replacements needed as a result of a blown fuse, age, and regular wear and tear, unless the Company can demonstrate that the equipment damage is based on the actions or equipment of DG operations. If over-duty breaker conditions no longer exist and the fault current mitigation device is no longer working, the Company would not be required to replace this device. The Company's incremental costs related to the purchase and installation of fault current mitigation technology will be deferred for recovery from customers.

i) Performance Requirements

For 13 kV and 27 kV over-duty circuit breakers, except upon the occurrence of extraordinary system conditions, the Company will replace a target of at least 50 over- duty circuit breakers during the calendar year (the "annual target level") and at least 180 over-duty circuit breakers during each three-year period (the "triannual target level").

There will be revenue adjustment applicable for the annual and for the triannual performance. If the Company does not achieve the annual target level for over-duty circuit breaker replacements, the Company will be subject to a $100,000 per breaker revenue adjustment with a maximum revenue adjustment of $1.5 million . If the Company does not achieve the triannual target level for over-duty circuit breaker replacements, the Company will be subject to an additional $100,000 per breaker revenue adjustment with a maximum revenue adjustment of $3 million.

ii) Selection and Prioritization of Replacements

The Company will, to the extent practicable, seek to include over-duty circuit breaker replacements in situations where maximum fault currents are between 100 and 103 percent of the breaker rating. The Company will determine the prioritization of breaker replacements. The Company will have at least one meeting of all interested DG parties annually to review implementation of the effort and to address prioritization of where to replace over-duty circuit breakers. This annual meeting should be done in conjunction with efforts to improve communications with the DG community.

iii) Extraordinary Circumstances Exception

Where the Company can demonstrate that extraordinary circumstances prevented it from achieving the target levels for the rate year, those circumstances will be factored in measuring the Company's compliance with the above requirements. The determination of whether extraordinary circumstances exist will be made on a case-by-case basis and will be based on the particular facts and circumstances presented.

iv) Reporting

The Company's annual report will: (i) report on the number of over-duty breakers in existence from January 1 through December 31 of the prior year; (ii) provide the status of the Company's efforts on replacing the over-duty breakers; (iii) identify all over-duty breakers that were replaced over the course of the prior calendar year; and (iv) describe the extraordinary circumstances, if any, that prevented the Company from achieving the target level for replacements.

Appendix 15 -- Safety Standards Pilot Program

Consolidated Edison Company of New York, Inc.
Case 16-E-0060
Electric Safety Standards

Operation of Eight-Year Underground Inspection Cycle Pilot

The eight-year underground inspection cycle is effective as of January 1, 2015.

The annual performance target for inspections shall be as follows in order to comply with the eight-year inspection cycle:

Underground Inspection Annual Goal	**Percentage**	**Cumulative Minimum**
First year inspection goal: 85% of annual target	85% of 12.5% in year one	10.625%
Second year inspection goal: 90% of annual target	90% of 12.5% in year two	21.875%
Third year inspection goal: 95% of annual target	95% of 12.5% in year three	33.75%
Fourth year inspection goal: 95% of annual target	95% of 12.5% in year four	45.625%
Fifth year inspection goal: 95% of annual target	95% of 12.5% in year five	57.5%
Sixth year inspection goal: 95% of annual target	95% of 12.5% in year six	69.375%
Seventh year inspection goal: 95% of annual target	95% of 12.5% in year seven	81.25%
Eighth year inspection goal: 100% of all facilities to be inspected	100% of 100% in year eight	100%

In all other respects, during the term of the Rate Plan, this program will be subject to the Commission's orders in the Electric Safety Standards proceeding (Case 04-M-0159) and related proceedings, including but not limited to any reporting requirements, exceptions, exclusions and the negative revenue adjustments specified in the Electric Safety Standards, as those requirements may be amended by the Commission. For example, if the Commission takes action to replace negative revenue adjustments with a scorecard or otherwise modifies the negative revenue adjustments, as proposed in Case 16-E-0323, such modification will be applicable to the eight-year program established in this Eight-Year Underground Inspection Cycle.

In its next electric rate filing for rates, to be effective January 1, 2020, the Company will review the pilot, which might be subject to a prospective adjustment. If the inspection cycle and/or inspection activities are changed, the Company will be provided a reasonable transition that recognizes the time needed to acquire, train and mobilize the additional resources to meet any revision to the underground inspection program.

If the Company does not file for rates to be effective January 1, 2020, then the pilot will be subject to review and adjustment in 2019. If Company and/or Staff believe that the inspection cycle and/or inspection activities should be changed, the Company may submit a petition: (a) for a change in the underground inspection program; (b) for recovery of costs associated with the modified underground inspection program, along with consideration of the other safety related programs; and c) premised on a reasonable transition that recognizes the time needed to acquire, train and mobilize the additional resources to meet any revision to the underground inspection program. If the Company files such a petition it will not be subject to a materiality threshold.

Appendix 16 -- Gas Performance Mechanism

Consolidated Edison Company of New York, Inc.
Cases 16-G-0061
Gas Safety Performance Metrics

The gas safety performance measures described herein will be in effect for the term of the Gas Rate Plan. Unless otherwise indicated, all gas safety measures and targets (and associated revenue adjustments)[1] for calendar year 2019 remain in effect thereafter unless and until changed by the Commission.[2]

Negative Revenue Adjustments

1. **Leak Management/Emergency Response/Damages**

a. Leak Management - Year-End Total Backlog

If the year-end total leak backlog (types 1,2, 2A, 2M and 3)[3] exceeds the targets set forth below for Rate Years 2017, 2018 and 2019, the following negative revenue adjustments will be accrued on the Company's books for the benefit of firm customers for each Rate Year that the performance measures noted below are not attained, as directed by the Commission. Backlog must be at or below target between December 25 and December 31. Rechecks for each day that fail recheck must be added back into that day's backlog.

2017	
600 or less	No adjustment
greater than 600	12 basis points[4]

[1] Negative revenue adjustments relating to the Gas Safety Performance metrics in this section shall not exceed 150 basis points in any calendar year, unless and until changed by the Commission.

[2] The 255 mile replacement target established below, for the three-year period 2017 to 2019, does not remain in effect beyond 2019. However, the miles of main removal per year will increase by five (5) miles per year until reaching a level of one hundred (100) miles per year and then remain at that level, unless and until changed by the Commission .

[3] These are defined in Company specification G-11809.

[4] The basis point negative revenue adjustment associated with each measure is stated on a pre-tax basis. The revenue requirement equivalent of a basis point on common equity capital per the gas revenue requirements under this

2018	
550 or less	No adjustment
greater than 550	12 basis points
2019	
500 or less	No adjustment
greater than 500	12 basis points

b. Emergency Response - 30 Minute Response Time

If Con Edison does not respond to gas leak or odor calls within 30 minutes for at least 75 percent of the calls for Rate Years 2017, 2018 and 2019, a negative revenue adjustment of 6 basis points will be accrued on the Company's books for the benefit of firm customers for each Rate Year that the performance measures are not attained, as directed by the Commission.

The Company may seek the following exclusion to operating performance under this measure:

> Gas leak and odor calls resulting from mass area odor complaints (unrelated to Company action/inaction or infrastructure) where the Company receives 10 odor complaints or more within any one hour period for the duration of the mass area odor.

Con Edison shall provide notification to safety@dps.ny.gov within seven (7) days of such event that the Company is seeking Staff's consent to the exclusion. Staff will respond within thirty (30) days stating whether it consents or does not consent to the requested exclusion.[5]

Proposal is estimated to be $400,000 in RY1, $440,000 in RY2 and $490,000 in RY3.

[5] This exclusion, as well as the right to petition the Commission pursuant to the General Provisions section below, also applies to the 45-Minute Response Time and 60-Minute Response Time measures.

c. Emergency Response - 45 Minute Response Time

If Con Edison does not respond to gas leak or odor calls within 45 minutes for at least 90 percent of the calls for Rate Years 2017, 2018 and 2019, a negative revenue adjustment of 4 basis points will be accrued on the Company's books for the benefit of firm customers for each Rate Year that the performance measures are not attained, as directed by the Commission.

d. Emergency Response - 60 Minute Response Time

If Con Edison does not respond to gas leak or odor calls within 60 minutes for at least 95 percent of the calls for Rate Year 2017, 2018 and 2019, a negative revenue adjustment of 2 basis points will be accrued on the Company's books for the benefit of firm customers for each Rate Year that the performance measures are not attained, as directed by the Commission.

e. Damage Prevention

All damages will be tracked, measured and counted following the guidelines for the data reported for the Annual Gas Safety Performance Measures report.

f. Damages to Gas Facilities Resulting from Mismarks

If the total number of damages to Company gas facilities resulting from mismarks made by the Company and its contractors with respect to the location of Company gas facilities exceeds the targets set forth below per 1,000 one-call tickets[6] in Rate Years 2017, 2018 and 2019, the negative revenue adjustment associated with such targets will be accrued on the Company's books for the benefit of firm customers for each Rate Year that the performance measure noted below is not attained, as directed by the Commission.

<u>2017</u>

0.53 or less	No adjustment
greater than 0.53	7 basis points

<u>2018</u>

0.50 or less	No adjustment
greater than 0.50	7 basis points

<u>2019</u>

0.47 or less	No adjustment
greater than 0.47	7 basis points

In the event the Company does not make a base rate filing seeking new rates to go into effect on January 1, 2020, the following target will apply after December 31, 2019, until changed by the Commission:

0.44 or less	No adjustment
greater than 0.44	7 basis points

g. Damages by Company Employees and Company Contractors

If the total number of damages to Company gas facilities made by Company employees and Company contractors exceeds the targets set forth below per 1,000 one-call tickets in Rate Years 2017, 2018 and 2019, the negative revenue adjustment associated with such target will be accrued on the Company's books for the benefit of firm customers for each Rate Year that the

[6] For the purposes of this section, one-call tickets are defined as locate requests involving a work area in the Company's Bronx, Queens, Manhattan and Westchester service territory only.

performance measure noted below is not attained, as directed by the Commission.

2017

0.34 or less	No adjustment
greater than 0.34	7 basis points

2018

0.31 or less	No adjustment
greater than 0.31	7 basis points

2019

0.28 or less	No adjustment
greater than 0.28	7 basis points

h. Total Damages

If the number of total damages to Company gas facilities made by any party exceeds the targets set forth below per 1,000 one-call tickets in Rate Years 2017, 2018 and 2019, the negative revenue adjustment associated with such target will be accrued on the Company's books for the benefit of firm customers for each Rate Year that the performance measure noted below is not attained, as directed by the Commission.

2017

1.94 or less	No adjustment
greater than 1.94	4 basis points

2018

1.92 or less	No adjustment
greater than 1.92	4 basis points

2019

1.90 or less	No adjustment
greater than 1.90	4 basis points

2. **Gas Main Replacement**

The Company will remove from service 255 miles of 12-inch and under cast iron and unprotected steel gas main during the three Rate Year period 2017 to 2019. The Company will remove a minimum of 80 miles in 2017, 85 miles in 2018 and 90 miles in 2019. The Company will remove from service segments identified under its Main Replacement Program ("MRP") model of at least: 70 miles in 2017, 75 miles in 2018 and 80 miles in 2019. During the term of this rate plan, the Company will work to incorporate pipe diameters above 12-inch into the MRP model.

For each Rate Year, no more than 10 miles of leak-prone gas main removed from service from other programs (*e.g.*, oil-to-gas conversions) will be counted towards the annual performance target.

If the Company does not meet the annual target for removal of leak-prone gas main in 2017, 2018 or 2019, the Company will accrue on the Company's books of account a negative revenue adjustment equivalent to 8 basis points for such Rate Year(s), which will be applied to the benefit of firm customers, as directed by the Commission.

If the Company does not remove from service a total of 255 miles of leak prone pipe over the three-year period 2017 through 2019, a negative revenue adjustment equivalent to 24 basis points will be accrued on the Company's books for the benefit of firm service customers; provided, however, if the Company incurs a negative revenue adjustment in any Rate Year, the 24 basis point negative revenue adjustment will be reduced by the negative revenue adjustment incurred for that year(s).

3. **<u>Gas Regulations Performance Measure</u>**

This metric applies to instances of noncompliance (violations) with the gas safety regulations set forth below that are identified in Staff field and records audits. The categorization of violations hereunder as "High" or "Other" Risk is for administrative purposes of this metric only and do not constitute an admission by the Company as to the level of risk associated with any such regulation or the violation thereunder or that there is any risk associated with a violation.

Only violations identified and included in Staff field and record audit letters may be counted for purposes of this metric. At the conclusion of each audit, Staff and the Company will have a compliance meeting where Staff will present its findings to the Company, including which violation(s), if any, that Staff recommends be subject to this metric. The Company will have five (5) business days from the date of the compliance meeting to cure any identified document deficiency. Only official Company records, as defined in the Company's Operating and Maintenance plan, will be considered by Staff as a cure to a document deficiency. Violations that encompass more than one code section shall only count as one occurrence for this metric.[7]

Negative revenue adjustments, if any, would be applied as set forth in the following chart:

High Risk	Other Risk
RY1 – 1-20 (1/4 BP); 21-40 (1/2 BP); 41+ (1 BP) RY2 – 1-17 (1/4 BP); 18-33 (1/2 BP); 34+ (1 BP) RY3 – 1-13 (1/4 BP); 14-27 (1/2 BP); 28+ (1 BP)	RY1 – 1-45(1/9 BP); 46+ (1/3 BP) RY2 – 1-38 (1/9 BP); 39+ (1/3 BP) RY3 – 1-32 (1/9 BP); 33+ (1/3 BP)

In the event the Company does not make a base rate filing for new rates to go into effect on January 1, 2020, the following targets will be applied beginning on January 1, 2020, and remain in effect until changed by the Commission:

[7] However, this is without prejudice to a penalty action under the Public Service Law for any violation not counted under this metric.

High Risk	Other Risk
RY4 – 1-10 (1/4 BP); 11-20 (1/2 BP); 21+ (1 BP)	RY4 – 1-25 (1/9 BP); 26+ (1/3 BP)

The annual thresholds for negative revenue adjustments set forth above assume future Staff field and record audits consistent with audits conducted during the last five years.

Any negative revenue adjustments assessed under this metric shall not exceed 100 basis points for 2017, 2018 and 2019 and subsequent years unless and until changed by the Commission. For any code section (including subparts to a code section), the number of violations will be capped at ten for the negative revenue adjustment determination with the requirement that violations in excess of ten be addressed by a corrective action plan formally submitted to Staff by the Company to achieve compliance going forward. The corrective action plan will be provided in the Company's response to the audit letter.

Audits of liquefied natural gas ("LNG") facilities under Part 193 shall be included under this performance measure. The following Subparts of Part 193 are not applicable to the Company's operations: Part 193 - Subparts 2001, 2005, 2007, 2009, 2013, 2501, 2601, 2701, and 2901. The following Subparts of Part 193 shall be classified as "Other Risk" violations: Part 193 -Subparts 2011, 2521, 2607, 2627, 2629, 2631, 2633, 2639, 2703, 2711, 2719, and 2917. The remaining Subparts under Part 193 shall be classified as "High Risk."

This metric will be effective as of January 1, 2017, and will be measured on a calendar year basis. Violations/occurrences shall count in the year that the subject activity took place. For example, mapping errors that occurred prior to the Rate Year that is the subject of the audit would not be counted as a violation for that year. With respect to violations, only documentation or actions performed, or required to be documented or performed, on or after the date of the Commission's approval of the Joint Proposal will constitute an occurrence under the metric. Violations that initially occur before 2017, but continue into 2017, will be subject to this measure, for example, if a leak repair is performed in December 2016 and a follow-up inspection is required by December 28, 2016, but is not performed until January 2017, that would be a continuing violation that could count towards the 2017 performance measure.

Staff will submit its final audit reports to the Secretary under Case 16-G-0061. If the Company disputes any of Staff's final audit results, the Company may appeal Staff's findings to the Commission. If the Company elects to dispute any of Staff's findings, the Company will not incur a negative revenue adjustment on those Staff findings until such time as the Commission has issued a final decision on the Company's appeal. Upon Company request, the Commission may in its discretion, provide the Company with an evidentiary hearing prior to any final determination. The Company does not waive its right to seek judicial appeal of any Commission determination regarding a violation or penalty under applicable law.

4. **General Provisions**

The Company will report its annual performance in each of the areas set forth in this Appendix to the Secretary no later than sixty (60) days following the end of each calendar year. If a performance metric is not met, the associated negative revenue adjustment will be excused when the Company can demonstrate to the Commission extenuating circumstance that prevented the Company from meeting such performance metric. The determination of whether such circumstances exist will be made on a case-by-case basis by the Commission.

5. **Customer Satisfaction**

The levels of the Company's customers' satisfaction will be determined by surveys performed semi-annually by an outside vendor selected by the Company. The surveys, which will be the same surveys used in the current gas rate plan, will measure customers' satisfaction with the handling of calls to the Gas Emergency Response Center relating to gas service. Should the average of the two system-wide satisfaction survey indices for any Rate Year fall below 88.1 percent, Con Edison will provide a credit to customers, as directed by the Commission. The gross amount of the credit will be calculated proportionately from zero at a satisfaction level of 88.1 percent or above, up to a maximum of $3.3 million at a satisfaction level of 87.5 percent or below. System-wide emergencies will not be included in the surveys conducted under this provision.

Con Edison will submit reports on its performance of the customer satisfaction surveys twice a year following performance of each survey. The second report will also provide information for the annual period and, if applicable, any credit due customers.

Positive Rate Adjustments

1. **Leak Management/Main Replacement**

a. Leak Management - Year-End Total Backlog

The Company shall receive a positive revenue adjustment, up to an annual maximum of 5 basis points, for eliminating the highest volume Type 3 leaks below the total leak backlog (Type 1, 2, 2A and 3) annual goals of 600 in 2017, 550 in 2018 and 500 in 2019. The listing of Type 3 leaks is to be established from a leak record data based ranking by the Company until methane emissions prioritization methodology ranking is provided. When methane emissions prioritization methodology ranking is provided, the remaining leaks to be eliminated on the Company list will be replaced by the remaining leaks (from highest to lowest) on the methane emissions prioritization methodology provider's list. If 28 of the top 30 highest volume Type 3 leaks (highest to lowest) are eliminated from the year-end backlog (after adding back in failed rechecks), Company will earn 1 basis point; if 56 of the top 60 leaks are eliminated, Company will earn 2 basis points; if 84 of the top 90 leaks are eliminated, 3 basis points; if 112 of the top 120 leaks are eliminated, Company will earn 4 basis points; and if 140 of the list of 150 leaks are eliminated, the Company will earn 5 basis points. To the extent the Type 3 leak backlog is below 150, the difference between 150 and the actual Type 3 leak backlog will count towards the Company's efforts to achieve each of the aforementioned targets under this incentive.

b. <u>Gas Main Replacement</u>

In the event the Company replaces or eliminates leak-prone pipe in excess of 80 miles in Rate Year 2017, 85 miles in Rate Year 2018, and/or 90 miles in Rate Year 2019, for each whole mile in excess of the calendar year target plus one whole mile, the Company shall receive a positive revenue adjustment of 2 basis points per additional whole mile, capped at a maximum of 10 basis points (five miles) per calendar year.

The Table below shows the basis points available for different mileages of Leak Prone Pipe replaced in each Rate Year. At the conclusion of this rate plan, the RY3 targets will continue to be in effect until the Company's next rate plan.

Basis Points Incentive If The Miles of LPP Replacement Is:					
Year	2	4	6	8	10
RY1	82-83	83-84	84-85	85-86	86+
RY2	87-88	88-89	89-90	90-91	91+
RY3	92-93	93-94	94-95	95-96	96+

Case 16-G-0061 Summary CECONY Gas Safety Metrics

GAS SAFETY METRIC	Criteria	Unit	CY17 Basis Points	CY17 Annual Limit	CY17 Target	CY18 Basis Points	CY18 Annual Limit	CY18 Target	CY19 Basis Points	CY19 Annual Limit	CY19 Target	CYs Post Rate Plan Basis Points	CYs Post Rate Plan Annual Limit	CYs Post Rate Plan Target
LEAK BACKLOG	Total of Type 1, 2 and 2A	-	-	12	-	-	12	-	-	12	-	-	12	-
	Total of Type 1, 2, 2A and 3	-	12		600	12		550	12		500	12		500
LEAK PRONE PIPE	Total Replacement Min.	miles	8	8	80	8	8	85	8	8	90	8	8	90+5 to 100
	Total Three Year Replacement		-		-	-		-	24		255	-		-
EMERGENCY RESPONSE TIME	30 minutes	%	6	12	75	6	12	75	6	12	75	6	12	75
	45 minutes	%	4		90	4		90	4		90	4		90
	60 minutes	%	2		95	2		95	2		95	2		95
SAFETY VIOLATION OCCURRENCES (ANNUAL RECORD AND FIELD AUDIT)	High Risk (for each up to)	-	1/4 per	100	20	1/4 per	100	17	1/4 per	100	13	1/4 per	100	10
	High Risk (for each up to)	-	1/2 per		40	1/2 per		33	1/2 per		27	1/2 per		20
	High Risk (for each above)	-	1 per			1 per			1 per			1 per		
	Other Risk (for each up to)	-	1/9 per		45	1/9 per		38	1/9 per		32	1/9 per		25
	Other Risk (for each above)	-	1/3 per			1/3 per			1/3 per			1/3 per		
DAMAGE PREVENTION (PER 1000 ONE-CALL TICKETS)	Overall	-	4	18	1.94	4	18	1.92	4	18	1.90	4	18	1.90
	Mismark	-	7		0.53	7		0.50	7		0.47	7		0.44
	CECONY or CECONY Contractor	-	7		0.34	7		0.31	7		0.28	7		0.28
Total Annual Limit				150			150			150			150	

HIGH RISK SECTIONS PART 255		
ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Material - General	255.53(a),(b),(c)	HIGH
Transportation of Pipe	255.65	HIGH
Pipe Design - General	255.103	HIGH
Design of Components - General Requirements	255.143	HIGH
Design of Components - Flexibility	255.159	HIGH
Design of Components - Supports and anchors	255.161	HIGH
Compressor Stations: Emergency shutdown	255.167	HIGH
Compressor Stations: Pressure limiting devices	255.169	HIGH
Compressor Stations: Ventilation	255.173	HIGH
Valves on pipelines to operate at 125 psig or more	255.179	HIGH
Distribution line valves	255.181	HIGH
Vaults: Structural Design requirements	255.183	HIGH
Vaults: Drainage and waterproofing	255.189	HIGH
Protection against accidental overpressuring	255.195	HIGH
Control of the pressure of gas delivered from high pressure distribution systems	255.197	HIGH
Requirements for design of pressure relief and limiting devices	255.199	HIGH
Required capacity of pressure relieving and limiting stations	255.201	HIGH
Qualification of welding procedures	255.225	HIGH
Qualification of Welders	255.227	HIGH
Protection from weather	255.231	HIGH
Miter Joints	255.233	HIGH
Preparation for welding	255.235	HIGH
Inspection and test of welds	255.241(a),(b)	HIGH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(a)-(e)	HIGH
Welding inspector	255.244(a),(b),(c)	HIGH
Repair or removal of defects	255.245	HIGH
Joining Of Materials Other Than By Welding - General	255.273	HIGH
Joining Of Materials Other Than By Welding - Copper Pipe	255.279	HIGH
Joining Of Materials Other Than By Welding - Plastic Pipe	255.281	HIGH
Plastic pipe: Qualifying persons to make joints	255.285(a),(b),(d)	HIGH
Notification requirements	255.302	HIGH
Compliance with construction standards	255.303	HIGH
Inspection: General	255.305	HIGH
Inspection of materials	255.307	HIGH
Repair of steel pipe	255.309	HIGH
Repair of plastic pipe	255.311	HIGH
Bends and elbows	255.313(a),(b),(c)	HIGH
Wrinkle bends in steel pipe	255.315	HIGH

HIGH RISK SECTIONS PART 255		
ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Installation of plastic pipe	255.321	HIGH
Underground clearance	255.325	HIGH
Customer meters and service regulators: Installation	255.357(d)	HIGH
Service lines: Installation	255.361(e),(f),(g),(h),(i)	HIGH
Service lines: Location of valves	255.365(b)	HIGH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455(d),(e)	HIGH
External corrosion control: Buried or submerged pipelines installed before August 1, 1971	255.457	HIGH
External corrosion control: Protective coating	255.461(c)	HIGH
External corrosion control: Cathodic protection	255.463	HIGH
External corrosion control: Monitoring	255.465(a),(e)	HIGH
Internal corrosion control: Design and construction of transmission line	255.476(a),(c)	HIGH
Remedial measures: General	255.483	HIGH
Remedial measures: transmission lines	255.485(a),(b)	HIGH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255.505(a),(b),(c),(d)	HIGH
General requirements (UPGRADES)	255.553 (a),(b),(c),(f)	HIGH
Upgrading to a pressure of 125 PSIG or more in steel pipelines	255.555	HIGH
Upgrading to a pressure less than 125 PSIG	255.557	HIGH
Conversion to service subject to this Part	255.559(a)	HIGH
General provisions	255.603	HIGH
Operator Qualification	255.604	HIGH
Essentials of operating and maintenance plan	255.605	HIGH
Change in class location: Required study	255.609	HIGH
Damage prevention program	255.614	HIGH
Emergency Plans	255.615	HIGH
Customer education and information program	255.616	HIGH
Maximum allowable operating pressure: Steel or plastic pipelines	255.619	HIGH
Maximum allowable operating pressure: High pressure distribution systems	255.621	HIGH
Maximum and minimum allowable operating pressure: Low pressure distribution systems	255.623	HIGH
Odorization of gas	255.625(a),(b)	HIGH
Tapping pipelines under pressure	255.627	HIGH
Purging of pipelines	255.629	HIGH
Control Room Management	255.631(a)	HIGH
Transmission lines: Patrolling	255.705	HIGH
Leakage Surveys - Transmission	255.706	HIGH
Transmission lines: General requirements for repair procedures	255.711	HIGH

HIGH RISK SECTIONS PART 255		
ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Transmission lines: Permanent field repair of imperfections and damages	255.713	HIGH
Transmission lines: Permanent field repair of welds	255.715	HIGH
Transmission lines: Permanent field repair of leaks	255.717	HIGH
Transmission lines: Testing of repairs	255.719	HIGH
Distribution systems: Leak surveys and procedures	255.723	HIGH
Compressor stations: procedures	255.729	HIGH
Compressor stations: Inspection and testing relief devices	255.731	HIGH
Compressor stations: Additional inspections	255.732	HIGH
Compressor stations: Gas detection	255.736	HIGH
Pressure limiting and regulating stations: Inspection and testing	255.739(a),(b)	HIGH
Regulator Station Overpressure Protection	255.743(a),(b)	HIGH
Transmission Line Valves	255.745	HIGH
Prevention of accidental ignition	255.751	HIGH
Protecting cast iron pipelines	255.755	HIGH
Replacement of exposed or undermined cast iron piping	255.756	HIGH
Replacement of cast iron mains paralleling excavations	255.757	HIGH
Leaks: Records	255.807(d)	HIGH
Leaks: Instrument sensitivity verification	255.809	HIGH
Leaks: Type 1	255.811(b),(c),(d),(e)	HIGH
Leaks: Type 2A	255.813(b),(c),(d)	HIGH
Leaks: Type 2	255.815(b),(c),(d)	HIGH
Leak Follow-up	255.819(a)	HIGH
High Consequence Areas	255.905	HIGH
Required Elements (IMP)	255.911	HIGH
Knowledge and Training (IMP)	255.915	HIGH
Identification of Potential Threats to Pipeline Integrity and Use of the Threat Identification in an Integrity Program (IMP)	255.917	HIGH
Baseline Assessment Plan(IMP)	255.919	HIGH
Conducting a Baseline Assessment (IMP)	255.921	HIGH
Direct Assessment (IMP)	255.923	HIGH
External Corrosion Direct Assessment (ECDA) (IMP)	255.925	HIGH
Internal Corrosion Direct Assessment (ICDA) (IMP)	255.927	HIGH
Confirmatory Direct Assessment (CDA) (IMP)	255.931	HIGH
Addressing Integrity Issues (IMP)	255.933	HIGH
Preventive and Mitigative Measures to Protect the High Consequence Areas (IMP)	255.935	HIGH
Continual Process of Evaluation and Assessment (IMP)	255.937	HIGH
Reassessment Intervals (IMP)	255.939	HIGH
General requirements of a GDPIM plan	255.1003	HIGH

HIGH RISK SECTIONS PART 255		
ACTIVITY TITLE	**CODE SECTION**	**RISK FACTOR**
Implementation requirements of a GDPIM plan.	255.1005	HIGH
Required elements of a GDPIM plan.	255.1007	HIGH
Required report when compression couplings fail.	255.1009	HIGH
Requirements a small liquefied petroleum gas (LPG) operator must satisfy to implement a GDPIM plan	255.1015	HIGH

HIGH RISK SECTIONS PART 261		
ACTIVITY TITLE	**CODE SECTION**	**RISK FACTOR**
Operation and maintenance plan	261.15	HIGH
Leakage Survey	261.17(a),(c)	HIGH
Carbon monoxide prevention	261.21	HIGH
Warning tag procedures	261.51	HIGH
HEFPA Liaison	261.53	HIGH
Warning Tag Inspection	261.55	HIGH
Warning tag: Class A condition	261.57	HIGH
Warning tag: Class B condition	261.59	HIGH

OTHER RISK SECTIONS PART 255		
ACTIVITY TITLE	**CODE SECTION**	**RISK FACTOR**
Preservation of records	255.17	OTH
Compressor station: Design and construction	255.163	OTH
Compressor station: Liquid removal	255.165	OTH
Compressor stations: Additional safety equipment	255.171	OTH
Vaults: Accessibility	255.185	OTH
Vaults: Sealing, venting, and ventilation	255.187	OTH
Calorimeter or calorimeter structures	255.190	OTH
Design pressure of plastic fittings	255.191	OTH
Valve installtion in plastic pipe	255.193	OTH
Instrument, control, and sampling piping and components	255.203	OTH
Limitations On Welders	255.229	OTH
Quality assurance program	255.230	OTH
Preheating	255.237	OTH
Stress relieving	255.239	OTH
Inspection and test of welds	255.241(c)	OTH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(f)	OTH
Plastic pipe: Qualifying joining procedures	255.283	OTH
Plastic pipe: Qualifying persons to make joints	255.285(c)(e)	OTH
Plastic pipe: Inspection of joints	255.287	OTH
Bends and elbows	255.313(d)	OTH
Protection from hazards	255.317	OTH
Installation of pipe in a ditch	255.319	OTH
Casing	255.323	OTH
Cover	255.327	OTH
Customer meters and regulators: Location	255.353	OTH
Customer meters and regulators: Protection from damage	255.355	OTH
Customer meters and service regulators: Installation	255.357(a)-(c)	OTH
Customer meter installations: Operating pressure	255.359	OTH
Service lines: Installation	255.361(a), (b), (c), (d)	OTH
Service lines: valve requirements	255.363	OTH
Service lines: Location of valves	255.365(a), (c)	OTH
Service lines: General requirements for connections to main piping	255.367	OTH
Service lines: Connections to cast iron or ductile iron mains	255.369	OTH
Service lines: Steel	255.371	OTH
Service lines: Cast iron and ductile iron	255.373	OTH
Service lines: Plastic	255.375	OTH
Service lines: Copper	255.377	OTH
New service lines not in use	255.379	OTH
Service lines: excess flow valve performance standards	255.381	OTH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455 (a)	OTH
External corrosion control: Examination of buried pipeline when exposed	255.459	OTH
External corrosion control: Protective coating	255.461(a), (b), (d), (e), (f), (g)	OTH

OTHER RISK SECTIONS PART 255		
ACTIVITY TITLE	CODE SECTION	RISK FACTOR
External corrosion control: Monitoring	255.465 (b)(c)(d)(f)	OTH
External corrosion control: Electrical isolation	255.467	OTH
External corrosion control: Test stations	255.469	OTH
External corrosion control: Test lead	255.471	OTH
External corrosion control: Interference currents	255.473	OTH
Internal corrosion control: General	255.475(a)(b)	OTH
Atmospheric corrosion control: General	255.479	OTH
Atmospheric corrosion control: Monitoring	255.481	OTH
Remedial measures: transmission lines	255.485(c)	OTH
Remedial measures: Pipelines lines other than cast iron or ductile iron lines	255.487	OTH
Remedial measures: Cast iron and ductile iron pipelines	255.489	OTH
Direct Assessment	255.490	OTH
Corrosion control records	255.491	OTH
General requirements (TESTING)	255.503	OTH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255.505 (e),(h), (i)	OTH
Test requirements for pipelines to operate at less than 125 PSIG	255.507	OTH
Test requirements for service lines	255.511	OTH
Environmental protection and safety requirements	255.515	OTH
Records (TESTING)	255.517	OTH
Notification requirements (UPGRADES)	255.552	OTH
General requirements (UPGRADES)	255.553 (d)(e)	OTH
Conversion to service subject to this Part	255.559(b)	OTH
Change in class location: Confirmation or revision of maximum allowable operating pressure	255.611(a), (d)	OTH
Continuing surveillance	255.613	OTH
Odorization	255.625 (e)(f)	OTH
Pipeline Markers	255.707(a),(c),(d),(e)	OTH
Transmission lines: Record keeping	255.709	OTH
Distribution systems: Patrolling	255.721(b)	OTH
Test requirements for reinstating service lines	255.725	OTH
Inactive Services	255.726	OTH
Abandonment or inactivation of facilities	255.727(b)-(g)	OTH
Compressor stations: storage of combustible materials	255.735	OTH
Pressure limiting and regulating stations: Inspection and testing	255.739 (c), (d)	OTH
Pressure limiting and regulating stations: Telemetering or recording gauges	255.741	OTH
Regulator Station MAOP	255.743 (c)	OTH
Service Regulator - Min.& Oper. Load, Vents	255.744	OTH
Distribution Line Valves	255.747	OTH
Valve maintenance: Service line valves	255.748	OTH
Regulator Station Vaults	255.749	OTH
Caulked bell and spigot joints	255.753	OTH
Reports of accidents	255.801	OTH
Emergency lists of operator personnel	255.803	OTH

OTHER RISK SECTIONS PART 255		
ACTIVITY TITLE	**CODE SECTION**	**RISK FACTOR**
Leaks General	255.805 (a), (b), (e), (g), (h)	OTH
Leaks: Records	255.807(a)-(c)	OTH
Type 3	255.817	OTH
Interruptions of service	255.823 (a)-(b)	OTH
Logging and analysis of gas emergency reports	255.825	OTH
Annual Report	255.829	OTH
Reporting safety-related conditions	255.831	OTH
General (IMP)	255.907	OTH
Changes to an Integrity Management Program (IMP)	255.909	OTH
Low Stress Reassessment (IMP)	255.941	OTH
Measuring Program Effectiveness (IMP)	255.945	OTH
Records (IMP)	255.947	OTH
Records an operator must keep	255.1011	OTH

OTHER RISK SECTIONS PART 261		
ACTIVITY TITLE	**CODE SECTION**	**RISK FACTOR**
High Pressure Piping - Annual Notice	261.19	OTH
Warning tag: Class C condition	261.61	OTH
Warning tag: Action and follow-up	261.63(a)-(h)	OTH
Warning Tag Records	261.65	OTH

Appendix 17 -- Customer Service Performance Mechanism

Consolidated Edison Company of New York, Inc.
Cases 16-E-0060, 16-G-0061
Customer Service Performance Mechanism

The Customer Service Performance Mechanism ("CSPM") described herein will be in effect for the term of the Rate Plan and thereafter unless and until changed by the Commission.

a. Operation of Mechanism

The CSPM establishes threshold performance levels for designated aspects of customer service. The threshold performance levels are detailed on page 6 of this Appendix. Failure by the Company to achieve the specified targets will result in a revenue adjustment of up to $40 million annually. All revenue adjustments related to the CSPM will be deferred for the benefit of customers.

b. Exclusions

Abnormal operating conditions are deemed to occur during any period of emergency, catastrophe, strike, natural disaster, major storm, or other unusual event not in the Company's control affecting more than 10 percent of the customers in an operating area during any month. A major storm will have the same definition as set forth in 16 NYCRR Part 97.

i) In the event abnormal operating conditions in one (1), two (2) or three (3) of the Company's six operating areas affect the Company's ability to perform any activity that is part of this CSPM, the data for the operating area(s) experiencing the abnormal operating conditions will be omitted from the calculation and the Company's results for any activity that is part of the CSPM that is affected by such abnormal operating conditions will be measured only by the data from the other operating area(s) for the period of the abnormal operating conditions.

ii) If abnormal operating conditions occur in more than three operating areas so that monthly results cannot be measured for a given activity, the month will be eliminated in the calculation of the actual annual average performance for that activity.

iii) In the event that abnormal operating conditions affecting the Company's ability to perform a given activity occur in more than three operating areas for an entire Rate Year, the activity will be inapplicable in that Rate Year and the associated revenue adjustment amount for that activity will also be inapplicable in that Rate Year.

iv) If changes in Company operations render it impractical to continue to measure performance in any activity, the measurement method and/or threshold standard will be revised or an alternative method or activity selected for the remainder of the period during which this CSPM is operative. Any such modifications must be mutually agreed to by Staff and the Company in writing. In the event Staff and the Company cannot agree to a modification, the revenue adjustment amount associated with the activity that can no longer be measured will be reallocated among the other activities for the remainder of the period during which this CSPM is operative.

c. Reporting

The Company will prepare an annual report on its performance that will be filed with the Secretary by March 1 following each Rate Year. Each report will state: (i) any changes anticipated to be implemented in the following measurement period in any activity reflected in this Proposal, (ii) a summary of the effect of any of the exclusions described herein and/or any significant changes in operations which led to the reported performance level during the measurement period; and (iii) whether a revenue adjustment is applicable, and if so, the amount of the revenue adjustment. The Company will maintain sufficient records to support such reports.

d. Threshold Standards

The Company’s threshold performance will be measured based on the Company's cumulative monthly performance for each Rate Year for the following four activities, except as otherwise noted.

i) **Commission Complaints**

Con Edison's Commission complaint performance measure will be the 12-month complaint rate per 100,000 customers as reported by the Office of Consumer Services each year for the 12-month period ending in December, based on the number of complaints received. The net number of customers used to determine the complaint rate will include only metered account customers (i.e., will not include sub-metered or master-metered consumers). A complaint is a contact by a customer, applicant, or customer’s or applicant’s agent that follows a contact with the Company about the issue of concern as to which the Company, having been given a reasonable opportunity to address the matter, has not satisfied the customer. The issue of concern must be one within the Company's responsibility and control, including an action, practice or conduct of the Company or its employees, not matters within the responsibility or control of an alternative service provider. Complaints resulting from the price of electric energy and capacity or the operation of the Company’s MSC and that do not otherwise present just cause for charging a complaint against the Company will not be counted as complaints for the purposes of the CSPM. One or more contacts by a rate consultant raising the same issue as to more than one account, whether such contacts are made at the same time or different times, will not be counted as more than one complaint if the issue is under consideration by the Department or the Commission and no Company deficiency is found. Contacts by customers about the Shared Meter Law will not be complaints if the contact is about the requirements of the Shared Meter Law and no Company deficiency is found. The annual report filed by the Company shall provide an accounting, without identifying specific customer information (*e.g.*, by listing complaints by reference number, without providing customer names), of any complaints that the Company believes should not be counted due to the provisions of this paragraph, and state the resulting adjusted Commission Complaint rate.

ii) **Call Answer Rate**

"Call Answer Rate" is the percentage of calls answered by a Company representative within thirty (30) seconds of the customer's request to speak to a representative between the hours of 9:00 AM and 5:00 PM Monday through Friday (excluding holidays). The performance rate is the sum of the system-wide number of calls answered by a representative within thirty (30) seconds divided by the sum of the system-wide number of calls answered by representatives.

iii) **Satisfaction of Callers, Visitors, and Emergency Contacts**

The average of the satisfaction index ratings on the semi-annual surveys (conducted during the second and fourth quarters) of emergency callers (electric only), Customer Experience Center (formerly referred to as Call Center callers (non-emergency)), and Service Center and Walk-in Center visitors, separately conducted by Communication Research Associates or another professional survey organization during each Rate Year. The Company shall notify Staff of any process instituted by the Company to change its survey contractor. The Company shall notify Staff at least six (6) months prior to making any material change to its survey questionnaire or survey methodologies. The Parties acknowledge that issues related to utility customer satisfaction surveys are being addressed in Case 15-M-0566, *In the Matter of Revisions to Customer Service Performance Indicators Applicable to Gas and Electric Corporations*.

iv) **Outage Notification**

The specific activities for communicating with customers, the public, and other external interests during defined electric service outage events remain as described by the Commission in Case 00-M-0095.[1] For each activity noted in that Order, performance that fails to meet the applicable threshold performance standard will result in a revenue adjustment at twice the level set forth in that Order (e.g, for each failure to complete a communication activity within the required time, the negative adjustment would be increased from $150,000 to $300,000). The overall amount at risk for Outage Notification ($8 million, established in Case 07-E-0523) shall remain unchanged.

[1] Case 00-M-0095, Joint Petition of Consolidated Edison, Inc. and Northeast Utilities for Approval of a Certificate of Merger, with All Assets Being Owned by a Single Holding Company, *Order Approving Outage Notification Incentive Mechanism* (issued April 23, 2002)

Customer Service Performance Mechanism
Incentive Targets

Indicator	Maximum Revenue Adjustment	Threshold Level	Revenue Adjustment
Commission Complaints	$ 9 million	</ = 2.1	N/A
		>2.1-</=2.4	$2,000,000
		>2.4-</=2.7	$5,000,000
		>2.7	$9,000,000
	$18 million		
Customer Satisfaction Surveys Emergency Calls (electric only)	$6 million	>/=84.2	N/A
		<84.2->/=81.2	$1,500,000
		<81.2->/=78.2	$3,000,000
		<78.2	$6,000,000
Customer Satisfaction Survey of Phone Center Callers (non-emergency)	$6 million	>/=87.8	N/A
		<87.8->/=85.8	$1,500,000
		<85.8->/=83.8	$3,000,000
		<83.8	$6,000,000
Customer Satisfaction Survey of Service Center Visitors	$6 million	>/=88.1	N/A
		<88.1->/=86.1	$1,500,000
		<86.1->/=84.1	$3,000,000
		<84.1	$6,000,000
Outage Notification	$ 8 million	Communication Timeliness; Communication Content	$300,000 per communication activity
Call Answer Rate	$ 5 million	>/=66.0%	N/A
		<66%->/=64.2%	$1,000,000
		<64.2%->/=62.5%	$2,000,000
		<62.5%->/=60.7%	$4,000,000
		<60.7%	$5,000,000

Appendix 18 -- AMI Metrics

Appendix 18 - Advanced Metering Infrastructure (AMI) Scorecard / Metrics

Category	Service/Function	Metric	Description	Target	Report Start Date	Update Frequency
Customer Engagement	Energy Savings Messages / Tools	Customers using the AMI Portal	Percentage of customers in each region with AMI meters that log on to usage/analytics page (available via web, mobile web, tablet or apps) at least once during the reporting period, broken down by service class and low income / non-low income. Baseline established based on data from at least the first 6 months of deployment in each region. Improvement measured against regional baselines each reporting period. Additional reporting (no targets established): Percentage of customers that logged on more than once during each reporting period.	To be set once-baseline has been established for each region, and following Staff review.	4/30/2018	Semi annual
		Customers targeted with energy saving messaging	Percentage of customers with AMI meter at least 30 days that are targeted during the reporting period with messages regarding their energy savings tools, personalized usage and/or savings tips. Data broken out by low income and non-low income. Additional reporting (no targets established): If possible, Company will track and report for each reporting period the number of customers that use the online portal once they receive targeted messaging.	Percentage of customers that will be targeted will be established after Staff review and prior to initial report on 4/30/2018.	4/30/2018	Semi annual
		Near-Real Time Data	Number of customers with an AMI meter that have access to near real-time data via the web, mobile web, tablet or apps.	Starting at end of 3Q2018, 99% of meters deployed will be presented with near real time data. Refer to roll-out plan for quantities on a quarterly basis.	4/30/2019	Semi annual
	Awareness / Education	Customer Awareness of AMI*	Customer awareness of AMI technology, features and benefits, measured by surveys of customers in each region. Baseline established on a regional basis prior to roll-out of AMI in each area (March 2017 for Staten Island). Subsequent progress ("check-in surveys") measured semi-annually, beginning at least 6 months after the beginning of deployment, through the end of roll-out in each region. Check-in surveys will draw from customers with AMI meters only. In the post-deployment surveys, the Company will measure low-income awareness. See Note 3 below.	To be set for each region following baseline surveys that will be done three months prior to-the deployment. Staff will review.	4/30/2018	Semi annual

Category	Service/Function	Metric	Description	Target	Report Start Date	Update Frequency
Customer Engagement	Awareness / Education	Targeted Energy Forum	Con Edison hosted forums where the Company will provide in-depth information on the AMI plan, features, and benefits.	2 per region. Staff will review.	4/30/2018	Annual
	Green Button Connect My Data	Green Button Connect My Data	Number of customers who share their data via GBC in the reporting period plus number of customers that continue to share based on elections made in a prior period. Establish baseline using calendar year 2018 data.	To be set once baseline has been established, and following Staff review.	4/30/2019	Semi annual
	TOU (Time of Use) and TVP (Time Variable Pricing) tariffs	Customer Adoption of Time-Variant Rates	Number of customers with AMI meters that adopt a TOU or TVP tariff, expressed as a number and percentage of each by rate (e.g., Electric SC1 Rate III, Electric SC2 Rate II, pilot rates, etc.). The Company will document the number of customers on existing TOU or TVP rates prior to the start of AMI roll-out, for comparison purposes.	Company will report this information for tracking purposes only.	4/30/2018	Semi annual
	Community Outreach	Community Organization Events	Number of organizational events attended where information on AMI plan, features, and benefits would be presented.	20 presentations per year. With a minimum of 4 per region in each year until the conclusion of deployment in that region.	4/30/2018	Semi annual
Billing	Billing	Estimated Bills	Percentage of bills that were estimated for accounts with AMI meters during the reporting period.	< 1.5 % of bills will be estimated for customers with AMI	4/30/2018	Semi annual
Outage Management	Power Quality	Proactive power quality issue identification	Reduction in truck rolls due to power quality complaints.	500 per year after full deployment of AMI in 2022.	4/30/2018	Annual
	False Outages	Number of false outages resolved through AMI	Number of false outages that were found through AMI that Company did not have to send a crew or call to confirm.	9000 per year once AMI is fully deployed in 2022.	4/30/2018	Annual
	Meter Reading Costs	Reduction in manual meter operations costs	Track avoided meter operations O&M costs and report.	In accordance with O&M reductions filed in the 2016 Rate Case.	4/30/2018	Annual
	Environmental benefits resulting from less vehicle usage	Reduction in vehicle fuel consumption and vehicle emissions	Reduction in vehicle fuel consumption and vehicle emissions due to reduction in manual meter reading costs, reduction in false outages and reduction in number of field visits during outages to confirm a customer has power.	This goal will be aligned with the information provided in the November 2015 Business Plan on tons of carbon avoided.	4/30/2018	Annual

Category	Service/Function	Metric	Description	Target	Report Start Date	Update Frequency
System Operation and Environmental Benefits	Conservation Voltage Optimization (CVO)-Networks	Number of networks deployed with CVO	Number of networks with AMI deployed and have implemented CVO.	Substation voltage schedules will be updated to incorporate the AMI feedback loop within one year following the installation of all AMI meters associated with that station. Note that for this reason, kWH reductions noted below cannot be reported on until mid-2019.	10/31/2018	Semi annual
	Conservation Voltage Optimization (CVO)-KWh savings	Quantify kWh savings attributed to CVO	Quantify kWh savings attributed to CVO.	Goal is 1.5% energy savings based on calculations verified using a similar measurement and verification process as used for Brooklyn/Queens Demand Management project, subject to future changes in load composition.	10/31/2019	Annual
	Conservation Voltage Optimization (CVO)-Environmental benefits	Environmental benefits due to CVO	Provide total fuel consumption savings and corresponding emissions reductions.	By the end of 2022, reduction in fossil fuel consumption resulting in CO2 emission reductions of 229,000 metric tons in the CECONY service area and 369,000 metric tons in all of New York State annually, subject to changes in generation fuel mix and imports/exports with neighboring pools.	10/31/2019	Annual
AMI Meter Deployment	Number of AMI meters installed	Number of AMI meters installed	Provide the number and percentage of AMI meters installed and working by borough and in Westchester. Information will be provided on a quarterly basis.	See Note 4 for target.	4/30/2018	Semi annual

Note 1 : Twelve months after AMI installation has been completed in each region, the Company will perform a survey to examine the link, if any, between AMI deployment and Distributed Energy Resource adoption. Results of this study will be provided at the next scheduled reporting interval.

Note 2 : The Company will file two reports in each calendar year, six months apart, with the Secretary to the Commission. The reports will contain Con Edison's eligibility for an Earnings Adjustment Mechanism (EAM) and Scorecard information. Information regarding the Company's eligibility for the EAM will be included in the report submitted after the post-deployment survey results are available; and this report will (1) provide the results from the customer surveys and (2) identify whether an earnings adjustment is applicable and the amount of the earnings adjustment.
All reports will no longer be required following the last reporting interval after completion of the AMI deployment.
Note 3 : In the post-deployment survey performed for each region, the Company will measure low income customer awareness. Results will be provided at the next scheduled reporting interval.

Note 4 : AMI Rollout Plan from Con Edison's November 2015 Benefit Cost Analysis spreadsheet, with exception for Westchester which has been accelerated from what was proposed in November 2015 Benefit Cost Analysis spreadsheet.

AMI Meter Deployment (000s)							
Quarter/Year	Staten Island	Westchester	Brooklyn	Manhattan	Bronx	Queens	Total
Q3 2017	32						32
Q4 2017	60	30					90
Q1 2018	60	60					120
Q2 2018	30	90	30				150
Q3 2018		90	60	30			180
Q4 2018		90	90	60			240
Q1 2019		90	90	90	30		300
Q2 2019		90	90	90	60		330
Q3 2019		40	90	120	75	5	330
Q4 2019		25	90	120	75	30	340
Q1 2020			90	120	75	60	345
Q2 2020			90	90	75	90	345
Q3 2020			90	90	75	90	345
Q4 2020			90	90	75	90	345
Q1 2021			60	60	75	150	345
Q2 2021			18	60	75	150	303
Q3 2021			6	60	75	150	291
Q4 2021			4	30	22	150	206
Q1 2022				30		40	70
Q2 2022				4		4	8
Total	182	605	988	1144	787	1009	4715

Appendix 19 -- Electric Revenue Allocation and Rate Design

Consolidated Edison Company of New York, Inc.

Case 16-E-0060

Electric Revenue Allocation and Rate Design

Revenue Allocation

Based on a three-year rate plan, the delivery revenue change for each Rate Year includes: (1) changes in delivery related revenues, e.g., total T&D revenue, including certain items related to the Monthly Adjustment Clause ("MAC"), competitive and non-competitive amounts; (2) a decrease in the MAC revenue requirement (Rate Year 1 only); (3) a change in the purchased power working capital component of the Merchant Function Charge ("MFC"); (4) an increase in the T&D delivery revenue to offset the reduction in the TCC imputation (Rate Year 1 only); (5) incremental program costs related to system peak reduction, energy efficiency above Efficiency Transition Implementation Plan ("ETIP") and Electric Vehicles ("EV") Programs (herein referred to as "New Programs"); and (6) an increase in delivery revenue to offset the projected decrease in revenue associated with the Low-Income Program and Reconnection Fee Waiver Program (Rate Year 1 only). The T&D delivery revenue change, including program costs related to the New Programs and incremental Low-Income Program and Reconnection Fee Waiver costs, was allocated to Con Edison customers and NYPA delivery service. The decrease in the MAC revenue requirement for Rate Year 1 was allocated to Con Edison full service and retail access customers. The change to the purchased power working capital is allocable only to Con Edison full service customers. The increase in the T&D delivery revenues related to the TCC imputation change is allocable only to Con Edison full service and retail access customers. Costs related to the New Programs are allocated to Con Edison and NYPA in the following manner: (1) 100% of energy efficiency and 95% of system peak reduction and EV program costs are allocated to Con Edison full service and retail access customers; and (2) 5% of system peak reduction and EV program costs are allocated to NYPA.

The Rate Year T&D delivery revenue change, less gross receipts taxes, for each Rate Year was allocated among the classes in four steps:

Step 1: Revenue Realignment

Con Edison and NYPA T&D delivery revenues were realigned in each Rate Year to address one-third of the revenue surpluses/deficiencies resulting from the Company's 2013 Embedded Cost of Service ("ECOS") study before applying the otherwise applicable revenue changes. The specific revenue adjustments are set forth in Table 1 to this Appendix.

Surplus classes are SC 6, SC 9 Rate I and SC 9 Rate II. Deficient classes are SC1, SC 2, SC5 Rate I and SC5 Rate II, SC 8 Rates I and II, and SC 12 Rates I. SC 12 Rate II is an average class (i.e., neither surplus nor deficient).

The revenue surpluses/deficiencies resulting from the 2013 ECOS study applicable to each customer class are shown on Table 1. The revenue surpluses/deficiencies are shown on Column (2) of Table 2 of this Appendix and were added to the bundled T&D revenue before the revenue change to establish the re-aligned bundled T&D revenue (Column (3) of Table 2).

Step 2: Allocation of T&D Revenue Change

The Rate Year T&D delivery revenue change was adjusted for changes to: (1) the MAC revenue requirement; (2) purchased power working capital, excluding GRT; (3) the TCC imputation; (4) the costs related to the New Programs; and (5) incremental costs associated with the Low Income Programs including the Reconnection Fee Waiver Program. The resultant Rate Year T&D related delivery revenue increase was then allocated as a uniform percentage increase to Con Edison and NYPA classes in proportion to their respective re-aligned bundled T&D revenues ((Column (3) of Table 2), with a final adjustment made to each class's T&D related delivery revenue change to reflect the ECOS revenue adjustments from Step 1. The portion of the New Program costs assigned to Con Edison is allocated to Con Edison full service and retail access customers in proportion to their respective re-aligned bundled T&D delivery revenues. The New Program costs assigned to each class including NYPA (Column (4b) (Rate Year 1 only) and Column (4a) (Rate Years 2 and 3) of Table 2) is then added to the class T&D related delivery revenue change (Column (4) of Table 2). The revenue increase associated with the TCC imputation change is allocable solely to Con Edison full service and retail access customers based on each class's pro rata share of bundled T&D delivery revenues as shown in Column 4a of Table 2 (Rate Year 1 only). The resultant total T&D delivery changes are shown in Column 5 of Table 2.

For Rate Year 1, the $7.2 million increase in the level of discounts associated with the change in the Low Income Program, as explained in the Proposal, was allocated to Con Edison classes and NYPA based on each class's pro rata share of bundled T&D delivery revenues. The incremental cost associated with the low income reconnection fee waivers reflected in the revenue allocation is $47,000 and includes recovery of the estimated annual reconnection fee waiver costs in excess of the costs at the current level (i.e., $547,000 less $500,000).

Step 3: Allocation of MAC Decrease and Changes to Purchased Power Working Capital

The impacts of the changes to the MAC revenue requirement (Rate Year 1 only) and Purchased Power Working Capital component of the MFC are shown in Columns (7a) and (7b), respectively, of Table 2 (pages 1, 2 and 3). The per kWh decrease in the MAC revenue requirement and the per kWh change in the Purchased Power Working Capital component of the MFC do not vary by customer class. The MAC decrease is applicable to Con Edison full service and retail access customers and the Purchased Power Working Capital component is applicable only to Con Edison full service customers.

Step 4: Total Class Revenue Change

The total revenue changes in Rate Years 1, 2 and 3 for each class are equal to the sum of each item described in Steps 2 and 3 (i.e., Column (8) in Table 2).

For Con Edison customers, the delivery revenue changes assigned to each class for the historic period were determined in three steps. First, the T&D delivery revenue change for each Rate Year was allocated among non-competitive revenues, customer charge revenues, reactive power demand charge revenues and competitive revenues. Customer charges for SCs 1, 2 and 6 were kept at their current levels as discussed in the Rate Design section of this Appendix. The Rate Year "non-competitive delivery revenue change" for each class was determined by adjusting the total Rate Year T&D related delivery revenue change allocated to each class by the changes in competitive service revenues, customer charge revenues (no changes in this case except for standby rates) and reactive power demand charge revenues for each class. Second, non-competitive T&D delivery revenue changes for each class were restated for the historic period (i.e., the twelve months ended December 31, 2013), the period for which detailed billing data were available. Revenue ratios were developed for each class by dividing the Rate Year non-competitive T&D revenues, less customer charge revenue, for each class by the historic period non-competitive T&D revenues, less customer charge revenue, for each class at the current rate level. For NYPA, the Rate Year T&D change was divided by the applicable revenue ratio to determine the rate change applicable for the historical period. Third, the revenue ratio for each class was applied to the Rate Year "non-competitive delivery revenue change" for each class to determine each class's "non- competitive delivery revenue change" for the historic period.

A summary of revenue impacts by class, on a delivery-only and total-bill basis for each of the Rate Years, is shown on Table 2a.

Rate Design

Revenue Neutral Rate Changes at Current (1/1/2016) Rate Level

Prior to adjusting delivery rates to reflect the rate changes allocated to the service classes for each Rate Year, demand and energy charges were redesigned revenue neutral to the January 1, 2016 rate level to better align revenues with costs for some of the demand-billed classes as described below.

A. Shift of Five Percent of Usage Revenues into Demand Revenues
Demand and energy rates were redesigned to reflect revenue neutral changes to shift five percent of usage revenues into demand revenues for Rate I of SCs 5, 8, 9 and 12.

B. Adjustment to High Tension and Low Tension Differentials
The high tension and low tension differential refers to the annualized high tension and low tension demand rates for demand billed customers compared with the high tension and low tension costs based on the 2013 ECOS study. For each Rate Year, Demand rates were redesigned, revenue neutral to the January 1, 2016 rate level, to adjust the high tension and low tension differentials for Rate I of SCs 5 and 12, Rate II of SCs 8 and 12, and NYPA. Demand rates were redesigned for these service

classes to eliminate one-third of the difference between: (1) annualized high tension rates over low tension rates relationship reflected in the January 1, 2016 rate level, and (2) high tension and low tension unit costs relationship for each of the Rate Years (i.e., address one third in Rate Year 1, plus one third in each of Rate Years 2 and 3).
A summary of the adjustments to the high tension and low tension differentials is shown on Table 3.

Design of Rates to Collect Change in Revenue Requirement

A. Non-Competitive Con Edison T&D Delivery Rates

1. In Rate Years 1, 2 and 3, the customer charges for SCs 1, 2 and 6, including voluntary time-of-day ("VTOD") rates, were kept at the current levels with the exception of customer charges for SC 2 unmetered service, which were reduced by $4.41 to reflect the removal of SC 2's allocated portion of metering costs in the 2013 ECOS study. Usage charges for all SC 2 customers were increased to offset the resulting revenue shortfall.

2. The per kWh charges in SC 1 Residential and Religious (Rate I), SC 2 General Small (Rate I) and the per kWh charges in SC 6 were changed to recover the entire non-competitive T&D delivery revenue requirement net of customer charge revenue, assigned to each respective rate class.

3. Voluntary TOD rates for SC 1 Rate II were designed to recover the overall SC 1 non-competitive delivery revenue requirement. Such rates were designed to be revenue neutral, i.e., the rates yield the same level of service class revenues that the Company would receive under the proposed conventional rates. The off-peak Domestic Hot Water Storage rate (Special Provision D) for SC1 Rate II was set equal to the SC 1 Rate II off-peak energy delivery rates.

4. Similar to SC 1 Rate II, Voluntary TOD rates for SC1 Rate III were designed to recover the overall SC 1 non-competitive delivery revenue requirement on a revenue-neutral basis.

5. Consistent with past practice, voluntary TOD rates for SC 2 Rate II were designed to recover the overall SC 2 non-competitive T&D related delivery revenue requirement. The rates were designed to be revenue neutral, i.e., the rates yield the same level of service class revenues that the Company would receive under the proposed conventional rates.

6. The revenue neutral redesigned demand charges of Rate I of SCs 5, 8, 9 and 12 were changed to recover the entire overall non-competitive T&D delivery revenue requirement applicable to each class. The minimum charges for Rate I of SCs 5, 8 and 12 demand rates were increased by five percent before the application of the non-competitive T&D rate percentage. The per kWh charges

for Rate I of SCs 5, 8, 9 and 12 were kept at the revenue neutral level (i.e., January 1, 2016 rate level) redesigned to reflect the shift of 5% usage revenues into demand revenues.

7. For SC 12 conventional customers billed for energy only (i.e., SC 12 Rate I), the per kWh charges and the minimum charge were increased by the non-competitive T&D delivery rate percentage change applicable to SC 12 (Rate I) customers. For SC 12 Rate III, rates are set equal to SC 2 Rate II rates.

8. The mandatory TOD rates for SC 5, 8, and 9, 12, and 13 and the voluntary TOD rates for SC 8, 9, and 12, were developed to collect the revised revenue requirement applicable to these classes solely through changes in demand charges. The per kWh rates were maintained at the current rate levels and set equal across classes for all three Rate Years. The demand rates of Rate II of SCs 5, 9 and 13 were set to recover the non-competitive revenue requirement for each of these classes. The redesigned demand rates of Rate II of SCs 8 and 12, adjusted to reflect the revenue neutral adjustment of the high tension and low tension differential for each of the Rate Years, were changed to recover the entire non-competitive revenue requirement for each of these classes for each Rate Year. Voluntary TOD rates were designed to recover the applicable class revenue requirement of all customers not billed under mandatory TOD rates.

9. Standby rates were developed consistent with the Commission's Opinion 01-04, Opinion and Order Approving Guidelines for the Design of Standby Service Rates, issued and effective October 26, 2001 ("Standby Rates Order") in Case 99-M-1470. In accordance with the standby rate guidelines, rates were developed for each standby class to be revenue neutral at the revised revenue level. The Standby Rates Order (p. 7) defines revenue neutral to mean that "the full service class (not any individual customer) would contribute the same revenues if the full class was priced under either the standard service class rates or the standby rates (given the historic usage patterns of the customers in that class)." The standby rates for SC 9 customers that are eligible for station-use rates (e.g., wholesale generators) taking service through the Company's distribution system were determined by removing the transmission component from the matrix contained in Appendix A of the PSC's Order of July 29, 2003, in Case 02-E-0781. Standby rates for SC 13 (Rate II) were developed by increasing the current rates by the non-competitive T&D delivery revenue percentage increase applicable to SC 13 Rate I.

10. The rates under Rider I – Experimental Rate Program for Multiple Dwellings were updated to recognize the SC 8 standby rates on which these rates are based.

11. The customer charges and distribution contract demand charges in SC 11 Buy-Back Service were set equal to the customer charges and contract demand charges of the standby rates for the respective class. In addition, the SC 11 and

other classes' reactive power charges applicable to induction generators were increased to the same level ($1.97 per billable kVar).

B. Design of NYPA Delivery Rates

After adjusting for any high tension and low tension differential on a revenue neutral basis as described above, Rate I and Rate II charges under the P.S.C. No. 12 delivery service rate schedule were changed by the overall T&D delivery revenue percentage change applicable to NYPA. Reactive power charges, including those applicable to induction generators, were increased to $1.97, the same as the rate set for Con Edison customers. Consistent with the standby rate guidelines, Rate III and IV rates were developed for each class within the NYPA tariff to be revenue neutral at the proposed revenue level, i.e., Rates III and IV were developed to produce the same delivery revenues as the equivalent non-standby rates.

C. Competitive Delivery Rates

Competitive delivery rates for Con Edison customers, i.e., the MFC and competitive metering charges, including the credit and collection ("C&C") related component of the Purchase of Receivables Discount Rate, were set in each Rate Year to reflect the revenue requirement for each Rate Year. Competitive metering credits applicable to NYPA were also adjusted to reflect the revenue requirement for each Rate Year. The MFC for Con Edison customers consists of two components: a supply-related component, including a purchased power working capital component, and a C&C related component. There were separate MFCs calculated for (1) SC 1 customers, (2) SC 2 customers, and (3) all other customers.

i. For each Rate Year, revised revenue levels for the MFC supply-related and C&C related components were based on percentages of delivery revenue as determined in the 2013 ECOS study. The resulting revenue requirement was then divided by the Rate Year full service customer sales in each group to determine the $/kWh supply-related portion of the MFC for each service class.

ii. The Rate Year revenue requirement for the C&C related component of the MFC was developed by multiplying the total Con Edison T&D Rate Year delivery revenue requirement by the percentage represented by C&C related costs for each group, inclusive of C&C costs attributable to the Purchase of Receivable ("POR") Discount Rate. The total Rate Year C&C related revenue requirement was split between full service and POR customers based on the respective split of full service and POR forecasted Rate Year kWh sales. The C&C related rate component to be recovered through the MFC from full service customers was then determined by dividing their share of the C&C related Rate Year revenue requirement for each group by the corresponding forecasted Rate Year kWh sales.

iii. The C&C related rate component to be recovered through the POR discount rate was set in each Rate Year to reflect the calculated portion of total C&C costs attributable to POR customers, the estimated Rate Year POR kWh sales, and the forecasted level of POR supply costs in the Rate Year.

iv. The proposed rate associated with the purchased power working capital component of the MFC was computed by dividing the purchased power working capital requirement for each Rate Year by forecasted Rate Year full-service customers' sales to derive a per kWh charge that was added to the applicable competitive supply related MFC component for each service group.

v. Competitive metering services recognize separate costing functions consisting of meter ownership, meter data service provider and combined meter service provider and meter installation costs. The Rate Year revenue requirements for the charges for meter ownership, meter services, and meter data services in each class eligible for competitive metering (i.e., SCs 5, 8, 9, 12 and 13 conventional demand-billed accounts) were developed similar to the Rate Year revenue requirement for the MFC components. The meter ownership, meter data service provider and combined meter service provider and meter installation costs applicable to Rate II of SC 5, 8, 9 and Rate I of SC 13 were changed by the overall Con Edison T&D average percent change. To calculate the $ per bill charges, the revenue requirements determined for each Rate Year were divided by each eligible class's annual number of bills. The metering charges for Rider M – Day Ahead Hourly Pricing customers were changed by the overall Con Edison T&D average percentage rate change in each Rate Year.

vi. The billing and payment processing charge applicable to Con Edison customers were maintained at the current level of $1.20 per bill. For customers with a combined electric and gas account, the portion of the charge applicable to electric service remains at $1.20 less the amount applicable to gas service (e.g., $0.60). Likewise, ESCOs pay $1.20 per bill per account, unless a customer has two separate ESCOs. In that case, the charge to the electric ESCO is $1.20 less the charge applicable to the gas ESCO (e.g., $0.60).

CASE 16-E-0060
Consolidated Edison Company of New York, Inc.
Embedded Cost-of-Service Study Results
For the Year 2013
Table 1A

	Service Classification	Initial Adjusted Surplus/Deficiency* ($000)	RY 1 Phase-in Surplus/Deficiency* ($000)	RY 1 Adjusted Surplus/Deficiency* ($000)	RY 2 Phase-in Surplus/Deficiency* ($000)	RY 2 Adjusted Surplus/Deficiency* ($000)	RY 3 Phase-in Surplus/Deficiency* ($000)
		(1)	(2) = (1) / 3	(3) = (1) - (2)	(4) = (1) / 3	(5) = (3) - (4)	(6) = (1) / 3
	NYPA	(5,209)	(1,736)	(3,473)	(1,736)	(1,737)	(1,737)
	Individual CECONY Classes						
SC 1	Residential	(37,334)	(12,445)	(24,889)	(12,445)	(12,444)	(12,444)
SC 2	General Small	(3,996)	(1,332)	(2,664)	(1,332)	(1,332)	(1,332)
SC 5	Traction	(10)	(3)	(7)	(3)	(4)	(4)
SC 5	TOD	(31)	(10)	(21)	(10)	(11)	(11)
SC 6	Street Lighting	321	107	214	107	107	107
SC 8	Apt. House	(1,646)	(549)	(1,097)	(549)	(548)	(548)
SC 8	TOD	(148)	(49)	(99)	(49)	(50)	(50)
SC 9	General Large	11,485	3,828	7,657	3,828	3,829	3,829
SC 9	TOD	37,038	12,346	24,692	12,346	12,346	12,346
SC 12	Apt. House Htg.	(470)	(157)	(313)	(157)	(156)	(156)
SC 12	TOD	0	0	0	0	0	0
	TOTAL CECONY CLASSES	5,209	1,736	3,473	1,736	1,737	1,737
	TOTAL SYSTEM	0	0	0	0	0	0

* Deficiencies shown as negative

Case No. 16-E-0060

Consolidated Edison Company of New York, Inc.

Estimated T&D Revenues for Rate Year Ending December 31, 2017

Levelized

Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Incl. GRT (b)		**$199,034,000**
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Excl. GRT		**$193,959,000**
Adjustment to Bundled Delivery Revenue Requirement for RY - Excl. GRT		
	MAC Change (Retained Generation)	$19,744,000
	Purchase Power Working Capital Change	$10,470,171
	Reconnection Fees Waiver for Low Income Program	$47,000
	Additional Discount for Low Income Program	$7,200,000
	TCC Imputation	-$15,000,000
	New Program Costs	-$3,156,406
	Total Adjustment	$19,304,765
T&D Related Delivery Revenue Increase		**$213,263,765**
Proposed % Rate Increase		4.31052546%

	RY Ending 12/31/2017 Bundled T&D Revenue at 1/1/16 Rate Level (a)	RY Deficiency /(Surplus)	Re-Aligned Bundled T&D Revenues at 1/1/16 Rate Level	Proposed RY Levelized Rate Increase Allocated to All Customers	Changes in TCC Imputation	Total New Program Costs allocable to CONED and NYPA	Levelized RY Total T&D Increase Including Deficiency /(Surplus) (b)	RY Total T&D % Rate Increase RY1 vs. Current	RY Target Bundled T&D Revenue at 1/1/2017 Rate Level (c)	Proposed RY MAC Increase Applicable to CECONY Customers	Proposed RY PPWC Change Applicable to CECONY Full Service Customers	Proposed RY Low Income Program Impact	RY Total Rate Increase Excl GRT
	(1)	(2)	(3)=(1)+(2)	(4)=(3)* 4.31052546%	(4a)	(4b)	(5)=(2)+(4)+(4a)+(4b)	(5a)=(5)/(1)	(6)=(1)+(5)	(7a)	(7b)	(7c)	(8)=(5)+ Σ[(7a)~(7c)]
SC1	$1,937,961,430	$12,445,000	$1,950,406,430	$84,072,766	$6,694,207	$1,346,691	$104,558,664	5.395291%	$2,042,520,094	-$6,108,855	-$5,981,033	-$7,247,000	$85,221,776
SC2	$356,751,240	$1,332,000	$358,083,240	$15,435,269	$1,229,017	$247,245	$18,243,531	5.113796%	$374,994,771	-$990,358	-$818,066	$0	$16,435,107
SC5 Rate I	$89,873	$3,000	$92,873	$4,003	$319	$64	$7,386	8.218264%	$97,259	-$430	-$538	$0	$6,418
SC5 Rate II	$3,128,000	$10,000	$3,138,000	$135,264	$10,770	$2,167	$158,201	5.057577%	$3,286,201	-$49,840	$0	$0	$108,361
SC6	$2,079,857	-$107,000	$1,972,857	$85,041	$6,771	$1,362	-$13,826	-0.664757%	$2,066,031	-$3,867	-$4,844	$0	-$22,537
SC8 Rate I&III	$137,748,811	$549,000	$138,297,811	$5,961,362	$474,667	$95,490	$7,080,519	5.140167%	$144,829,330	-$779,826	-$236,270	$0	$6,064,423
SC8 Rate II	$8,626,000	$49,000	$8,675,000	$373,938	$29,774	$5,990	$458,702	5.317668%	$9,084,702	-$58,433	$0	$0	$400,269
SC9 Rate I&III	$1,426,299,121	-$3,828,000	$1,422,471,121	$61,315,980	$4,882,222	$982,169	$63,352,371	4.441731%	$1,489,651,492	-$7,876,891	-$3,194,764	$0	$52,280,716
SC9 Rate II	$477,170,556	-$12,346,000	$464,824,556	$20,036,381	$1,595,376	$320,946	$9,606,703	2.013264%	$486,777,259	-$3,724,691	-$201,287	$0	$5,680,725
SC12 Rate I&III	$9,005,682	$157,000	$9,162,682	$394,960	$31,448	$6,327	$589,735	6.548477%	$9,595,417	-$65,308	-$18,299	$0	$506,128
SC12 Rate II	$11,316,444	$0	$11,316,444	$487,798	$38,840	$7,814	$534,452	4.722791%	$11,850,896	-$82,924	-$15,070	$0	$436,458
SC13	$1,919,000	$0	$1,919,000	$82,719	$6,586	$1,325	$90,630	4.722772%	$2,009,630	-$2,578	$0	$0	$88,052
CECONY	$4,372,096,014	-$1,736,000	$4,370,360,014	$188,385,481	$14,999,997	$3,017,590	$204,667,068	4.681212%	$4,576,763,082	-$19,744,001	-$10,470,171	-$7,247,000	$167,205,896
NYPA	$575,416,000	$1,736,000	$577,152,000	$24,878,284	$0	$138,818	$26,753,102	4.649350%	$602,169,102				$26,753,102
CECONY	$4,372,096,014	-$1,736,000	$4,370,360,014	$188,385,481	$14,999,997	$3,017,590	$204,667,068	4.681212%	$4,576,763,082	-$19,744,001	-$10,470,171	-$7,247,000	$167,205,896
Total	**$4,947,512,014**	**$0**	**$4,947,512,014**	**$213,263,765**	**$14,999,997**	**$3,156,408**	**$231,420,170**	**4.677506%**	**$5,178,932,184**	**-$19,744,001**	**-$10,470,171**	**-$7,247,000**	**$193,958,998**

Notes: (a) Excludes current Low Income Program credits of $48.00 million (i.e., $47.50 million of low income rate reductions and $500,000 of waived reconnection fees) for SC1 and PPWC.

(b) Excludes the proposed incremental Low Income Program credits of $7.247 million (i.e. $7.2 million of incremental low income rate reduction and $47,000 incremental waived reconnection fees).

(c) Excludes the proposed Low Income Program credits of $55.247 million for SC1 (i.e., $54.7 million of low income rate reductions and $547,000 of waived reconnection fees).

Case No. 16-E-0060
Consolidated Edison Company of New York, Inc.
Estimated T&D Revenues for Rate Year Ending December 31, 2018
Levelized

	RY2 Ending 12/31/2018 Bundled T&D Revenue at 1/1/16 Rate Level (a)	Proposed Total T&D % Rate Increase Effective 1/1/2017	RY2 Ending 12/31/2018 Bundled T&D Revenue at 1/1/17 Rate Level (b)	RY2 Deficiency /(Surplus)	Re-Aligned Bundled T&D Revenue at 1/1/17 Rate Level	Proposed RY2 Levelized Rate Increase Allocated to All Customers	RY 2 Total New Program Costs allocable to CONED and NYPA	Levelized RY2 Total T&D Increase Including Deficiency /(Surplus) (b)	RY2 Total T&D % Rate Increase RY2 vs. RY1	RY2 Target Bundled T&D Revenue at 1/1/2018 Rate Level (c)	Proposed RY2 MAC Increase Applicable to CECONY Customers	Proposed RY2 PPWC Change Applicable to CECONY Full Service Customers	Proposed RY2 Low Income Program Impact	RY2 Total Rate Increase Excl GRT
	(1a)	(1b)	(1)=(1a)*((1+(1b)	(2)	(3)=(1)+(2)	(4)=(3)* 3.57779598%	(4a)	(5)=(2)+(4)+(4a)	(5a)=(5)/(1)	(6)=(1)+(5)	(7a)	(7b)	(7c)	(8)=(5)+ Σ[(7a)~(7c)]
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Incl. GRT (b)						**$199,034,000**								
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Excl. GRT						**$193,959,000**								
Adjustment to Bundled Delivery Revenue Requirement for RY - Excl. GRT														
MAC Change (Retained Generation)						$0								
Purchase Power Working Capital Change						$219,590								
Reconnection Fees Waiver for Low Income Program						$0								
Additional Discount for Low Income Program						$0								
New Program Costs						-$6,891,664								
Total Adjustment						-$6,672,074								
T&D Related Delivery Revenue Increase						**$187,286,926**								
Proposed % Rate Increase						3.57779598%								
SC1	$1,965,677,920	5.395291%	$2,071,731,964	$12,445,000	$2,084,176,964	$74,567,600	$3,019,226	$90,031,826	4.345728%	$2,161,763,790	$0	-$125,442	$0	$89,906,384
SC2	$362,177,006	5.113796%	$380,697,999	$1,332,000	$382,029,999	$13,668,254	$553,425	$15,553,679	4.085569%	$396,251,678	$0	-$16,965	$0	$15,536,714
SC5 Rate I	$89,873	8.218264%	$97,259	$3,000	$100,259	$3,587	$145	$6,732	6.921724%	$103,991	$0	-$11	$0	$6,721
SC5 Rate II	$3,137,000	5.057577%	$3,295,656	$10,000	$3,305,656	$118,270	$4,789	$133,059	4.037406%	$3,428,715	$0	$0	$0	$133,059
SC6	$2,083,857	-0.664757%	$2,070,004	-$107,000	$1,963,004	$70,232	$2,844	-$33,924	-1.638837%	$2,036,080	$0	-$99	$0	-$34,023
SC8 Rate I&III	$139,750,874	5.140167%	$146,934,302	$549,000	$147,483,302	$5,276,652	$213,650	$6,039,302	4.110206%	$152,973,604	$0	-$5,184	$0	$6,034,118
SC8 Rate II	$9,023,000	5.317668%	$9,502,813	$49,000	$9,551,813	$341,744	$13,837	$404,581	4.257487%	$9,907,394	$0	$0	$0	$404,581
SC9 Rate I&III	$1,435,418,311	4.441731%	$1,499,175,731	-$3,828,000	$1,495,347,731	$53,500,491	$2,166,223	$51,838,714	3.457814%	$1,551,014,445	$0	-$66,604	$0	$51,772,110
SC9 Rate II	$477,518,698	2.013264%	$487,132,410	-$12,346,000	$474,786,410	$16,986,889	$687,795	$5,328,684	1.093888%	$492,461,094	$0	-$4,622	$0	$5,324,062
SC12 Rate I&III	$8,997,809	6.548477%	$9,587,028	$157,000	$9,744,028	$348,621	$14,116	$519,737	5.421253%	$10,106,765	$0	-$364	$0	$519,373
SC12 Rate II	$11,224,571	4.722791%	$11,754,684	$0	$11,754,684	$420,559	$17,028	$437,587	3.722661%	$12,192,271	$0	-$298	$0	$437,289
SC13	$1,916,000	4.722772%	$2,006,488	$0	$2,006,488	$71,788	$2,907	$74,695	3.722674%	$2,081,183	$0	$0	$0	$74,695
CECONY	$4,417,014,919		$4,623,986,338	-$1,736,000	$4,622,250,338	$165,374,687	$6,695,985	$170,334,672	3.683719%	$4,794,321,010	$0	-$219,589	$0	$170,115,083
NYPA	$583,582,000	4.649350%	$610,714,770	$1,736,000	$612,450,770	$21,912,239	$195,679	$23,843,918	3.904264%	$634,558,688				$23,843,918
CECONY	$4,417,014,919		$4,623,986,338	-$1,736,000	$4,622,250,338	$165,374,687	$6,695,985	$170,334,672	3.683719%	$4,794,321,010	$0	-$219,589	$0	$170,115,083
Total	**$5,000,596,919**		**$5,234,701,108**	**$0**	**$5,234,701,108**	**$187,286,926**	**$6,891,664**	**$194,178,590**	**3.709449%**	**$5,428,879,698**	**$0**	**-$219,589**	**$0**	**$193,959,001**

Notes: (a) Excludes current Low Income Program credits of $48.00 million (i.e., $47.50 million of low income rate reductions and $500,000 of waived reconnection fees) for SC1 and PPWC.
(b) Excludes the proposed incremental Low Income Program credits of $7.247 million (i.e. $7.2 million of incremental low income rate reduction and $47,000 incremental waived reconnection fees).
(c) Excludes the proposed Low Income Program credits of $55.247 million for SC1 (i.e., $54.7 million of low income rate reductions and $547,000 of waived reconnection fees).

Case No. 16-E-0060
Consolidated Edison Company of New York, Inc.
Estimated T&D Revenues for Rate Year Ending December 31, 2019
Levelized

	RY3 Ending 12/31/2019 Bundled T&D Revenue at 1/1/16 Rate Level (a)	Proposed Total T&D % Rate Increase Effective 1/1/2017	Proposed Total T&D % Rate Increase Effective 1/1/2018	RY3 Ending 12/31/2019 Bundled T&D Revenue at 1/1/18 Rate Level (b)	RY3 Deficiency /(Surplus)	Re-Aligned Bundled T&D Revenue at 1/1/18 Rate Level	Proposed RY3 Levelized Rate Increase Allocated to All Customers	RY 3 New Program Costs allocable to CONED and NYPA	Levelized RY3 Total T&D Increase Including Deficiency /(Surplus) (b)	RY3 Total T&D % Rate Increase RY3 vs. RY2	RY3 Target Bundled T&D Revenue at 1/1/2019 Rate Level (c)	Proposed RY3 MAC Increase Applicable to CECONY Customers	Proposed RY3 PPWC Change Applicable to CECONY Full Service Customers	Proposed RY3 Low Income Program Impact	RY3 Total Rate Increase Excl GRT
	(1a)	(1b)	(1c)	(1)=(1a)*((1+(1b))*((1+(1c))	(2)	(3)=(1)+(2)	(4)=(3)* 3.29219055%	(4a)	(5)=(2)+(4)+(4a)	(5a)=(5)/(1)	(6)=(1)+(5)	(7a)	(7b)	(7c)	(8)=(5)+ Σ[(7a)~(7c)]
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Incl. GRT (b)							**$199,034,000**								
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Excl. GRT							**$193,959,000**								
Adjustment to Bundled Delivery Revenue Requirement for RY - Excl. GRT															
MAC Change (Retained Generation)							$0								
Purchase Power Working Capital Change							$580,000								
Reconnection Fees Waiver for Low Income Program							$0								
Additional Discount for Low Income Program							$0								
New Program Costs							-$14,744,186								
Total Adjustment							-$14,164,186								
T&D Related Delivery Revenue Increase							**$179,794,814**								
Proposed % Rate Increase							3.29219055%								
SC1	$1,984,973,020	5.395291%	4.345728%	$2,182,983,679	$12,444,000	$2,195,427,679	$72,277,663	$6,604,057	$91,325,720	4.183527%	$2,274,309,399	$0	-$333,146	$0	$90,992,574
SC2	$366,137,337	5.113796%	4.085569%	$400,584,609	$1,332,000	$401,916,609	$13,231,861	$1,209,004	$15,772,865	3.937462%	$416,357,474	$0	-$44,613	$0	$15,728,252
SC5 Rate I	$89,873	8.218264%	6.921724%	$103,991	$4,000	$107,991	$3,555	$325	$7,880	7.577579%	$111,871	$0	-$29	$0	$7,851
SC5 Rate II	$3,142,000	5.057577%	4.037406%	$3,434,180	$11,000	$3,445,180	$113,422	$10,363	$134,785	3.924809%	$3,568,965	$0	$0	$0	$134,785
SC6	$2,082,857	-0.664757%	-1.638837%	$2,035,103	-$107,000	$1,928,103	$63,477	$5,800	-$37,723	-1.853616%	$1,997,380	$0	-$259	$0	-$37,982
SC8 Rate I&III	$140,656,366	5.140167%	4.110206%	$153,964,771	$548,000	$154,512,771	$5,086,855	$464,789	$6,099,644	3.961714%	$160,064,415	$0	-$13,634	$0	$6,086,010
SC8 Rate II	$9,292,000	5.317668%	4.257487%	$10,202,760	$50,000	$10,252,760	$337,540	$30,841	$418,381	4.100665%	$10,621,141	$0	$0	$0	$418,381
SC9 Rate I&III	$1,432,529,118	4.441731%	3.457814%	$1,547,892,576	-$3,829,000	$1,544,063,576	$50,833,515	$4,644,691	$51,649,206	3.336744%	$1,599,541,782	$0	-$173,103	$0	$51,476,103
SC9 Rate II	$479,468,570	2.013264%	1.093888%	$494,471,980	-$12,346,000	$482,125,980	$15,872,506	$1,450,281	$4,976,787	1.006485%	$499,448,767	$0	-$13,605	$0	$4,963,182
SC12 Rate I&III	$8,850,063	6.548477%	5.421253%	$9,940,810	$156,000	$10,096,810	$332,406	$30,372	$518,778	5.218669%	$10,459,588	$0	-$892	$0	$517,886
SC12 Rate II	$11,025,825	4.722791%	3.722661%	$11,976,391	$0	$11,976,391	$394,286	$36,026	$430,312	3.593002%	$12,406,703	$0	-$719	$0	$429,593
SC13	$1,917,000	4.722772%	3.722674%	$2,082,270	$0	$2,082,270	$68,552	$6,264	$74,816	3.593002%	$2,157,086	$0	$0	$0	$74,816
CECONY	$4,440,164,029			$4,819,673,120	-$1,737,000	$4,817,936,120	$158,615,638	$14,492,813	$171,371,451	3.555665%	$4,991,044,571	$0	-$580,000	$0	$170,791,451
NYPA	$590,038,000	4.649350%	3.904264%	$641,578,627	$1,737,000	$643,315,627	$21,179,176	$251,372	$23,167,548	3.611022%	$664,746,175				$23,167,548
CECONY	$4,440,164,029			$4,819,673,120	-$1,737,000	$4,817,936,120	$158,615,638	$14,492,813	$171,371,451	3.555665%	$4,991,044,571	$0	-$580,000	$0	$170,791,451
Total	**$5,030,202,029**			**$5,461,251,747**	**$0**	**$5,461,251,747**	**$179,794,814**	**$14,744,185**	**$194,538,999**	**3.562169%**	**$5,655,790,746**	**$0**	**-$580,000**	**$0**	**$193,958,999**

Notes: (a) Excludes current Low Income Program credits of $48.00 million (i.e., $47.50 million of low income rate reductions and $500,000 of waived reconnection fees) for SC1 and PPWC.
(b) Excludes the proposed incremental Low Income Program credits of $7.247 million (i.e. $7.2 million of incremental low income rate reduction and $47,000 incremental waived reconnection fees).
(c) Excludes the proposed Low Income Program credits of $55.247 million for SC1 (i.e., $54.7 million of low income rate reductions and $547,000 of waived reconnection fees).

Consolidated Edison Company of New York, Inc.
Case 16-E-0060 - Joint Proposal
Summary of Revenue Increases

Rate Year 1

Levelized

	Current Revenues		RY 1 Increases			Percentage Changes over Current Revenues		
Class	Bundled T&D Revenue at 1/1/16 Rates **Incl.** PPWC & $47.50 MM Low Income Credits and $0.5 M Reconnection Fee Waiver *	Total Bill Incl. MAC, MSC, SBC, 18-A and GRT at 1/1/16 Rates **	RY Total T&D Increase Incl. Low Income Discount, PPWC and MAC Change	RY Total Rate Increase Incl. Incremental Low Income Discount, PPWC, MAC Change due to Retained Generation, Reduction in MAC offsetting change in TCC and TSC Imputation and New MAC charges and NYPA Surcharges Excl. GRT ***	Total Bill Increase Incl. GRT	**T&D** % Increase Incl. Low Income discount and PPWC and MAC Over **RY1** Revenue @1/1/16 Rate Level	**T&D** % Increase Incl. Incremental Low Income discount and PPWC, MAC Change due to Retained Generation,Reduction in the MAC offsetting Changes in TCC and TSC Imputations and New MAC Charges and NYPA Surcharges Over **RY1** Revenue @1/1/16 Rate Level	**Total Bill** % Increase Over **RY1** Revenue @1/1/16 Rate Level
	(1)	(2)	(3)	(4)	(5)=(4)*GRT	(6)=(3)/(1)	(7)=(4)/(1)	(8)=(5)/(2)
SC1	$1,902,819,171	$3,474,966,347	$85,221,776	$80,380,718	$82,484,040	4.5%	4.2%	2.4%
SC2	358,509,880	614,206,876	16,435,107	15,650,282	16,059,803	4.6%	4.4%	2.6%
SC5 Rate I&III	91,030	199,872	6,418	6,078	6,237	7.1%	6.7%	3.1%
SC5 Rate II	3,128,000	15,475,850	108,361	68,864	70,666	3.5%	2.2%	0.5%
SC6	2,090,270	3,120,836	-22,537	-25,601	-26,271	-1.1%	-1.2%	-0.8%
SC8 Rate I&III	138,256,734	334,669,189	6,064,423	5,446,437	5,588,954	4.4%	3.9%	1.7%
SC8 Rate II	8,626,000	23,274,412	400,269	353,963	363,225	4.6%	4.1%	1.6%
SC9 Rate I&III	1,433,167,073	3,415,517,315	52,280,716	46,038,551	47,243,242	3.6%	3.2%	1.4%
SC9 Rate II	477,603,274	1,404,172,297	5,680,725	2,729,035	2,800,446	1.2%	0.6%	0.2%
SC12 Rate I&III	9,045,020	25,411,569	506,128	454,374	466,264	5.6%	5.0%	1.8%
SC12 Rate II	11,348,840	32,115,595	436,458	370,744	380,445	3.8%	3.3%	1.2%
SC13	1,919,000	2,624,940	88,052	86,009	88,260	4.6%	4.5%	3.4%
CECONY Subtotal	$4,346,604,292	$9,345,755,096	$167,205,896	$151,559,454	$155,525,311			
NYPA	$575,416,000	$1,291,113,971	$26,753,102	$26,932,878	$27,637,630	4.6%	4.7%	2.1%
CECONY	4,346,604,292	9,345,755,096	167,205,896	151,559,454	155,525,311	3.8%	3.5%	1.7%
Total	**$4,922,020,292**	**$10,636,869,067**	**$193,958,998**	**$178,492,332**	**$183,162,941**	**3.9%**	**3.6%**	**1.7%**

* Assumes the low income discount level of $47.50 M and $0.5 M Reconnection Fee Waiver. Incudes temporary credit of $47.776 M.
** Assumes the same MSC, MAC, 18-a, SBC factors used in the Company's initial filing. Includes supply estimates for RA customers and NYPA.
*** Excludes changes outside of rate case: (1) decreases to above market costs of NUG/public policy contracts and (2) a decrease in PJM OATT costs in RY 2.

Consolidated Edison Company of New York, Inc.
Case 16-E-0060 - Joint Proposal
Summary of Revenue Increases

Rate Year 2

Levelized

Class	RY 1 Revenues		RY 2 Increases			Percent Changes - RY 2 Increases over RY 1 Revenues		
	Bundled T&D Revenue at 1/1/17 Rates Incl. PPWC & $54.7 MM Low Income Credits and $0.547 M Reconnection Fee Waiver *	Total Bill Incl. MAC, MSC, SBC, 18-A and GRT at 1/1/17 Rates **	RY 2 Total T&D Increase Incl. Low Income Discount, PPWC and MAC Change	RY 2 Total Rate Increase Incl. Incremental Low Income Discount, PPWC, and New MAC Charges and NYPA Surcharges Excl. GRT ***	RY2 Total Bill Increase Incl. GRT	**T&D** % Increase Incl. Low Income discount and PPWC and MAC Over **RY2** Revenue @1/1/17 Rate Level	**T&D** % Increase Incl. Incremental Low Income discount and PPWC and New MAC Charges and NYPA Surcharges Over **RY 2** Revenue @1/1/17 Rate Level	**Total Bill** % Increase Over **RY2** Revenue @1/1/17 Rate Level
	(1)	(2)	(3)	(4)	(5)=(4)*GRT	(6)=(3)/(1)	(7)=(4)/(1)	(8)=(5)/(2)
SC1	$2,023,524,232	$3,611,991,685	$89,906,384	$92,174,238	$94,586,161	4.4%	4.6%	2.6%
SC2	381,650,021	639,206,496	15,536,714	15,903,100	16,319,236	4.1%	4.2%	2.6%
SC5 Rate I&III	97,878	206,109	6,721	6,878	7,058	6.9%	7.0%	3.4%
SC5 Rate II	3,295,656	15,556,236	133,059	151,268	155,226	4.0%	4.6%	1.0%
SC6	2,075,575	3,098,645	-34,023	-32,610	-33,463	-1.6%	-1.6%	-1.1%
SC8 Rate I&III	147,225,232	346,039,323	6,034,118	6,324,369	6,489,859	4.1%	4.3%	1.9%
SC8 Rate II	9,502,813	24,593,003	404,581	426,715	437,881	4.3%	4.5%	1.8%
SC9 Rate I&III	1,502,913,253	3,481,296,323	51,772,110	54,662,851	56,093,214	3.4%	3.6%	1.6%
SC9 Rate II	487,391,771	1,410,553,226	5,324,062	6,689,610	6,864,657	1.1%	1.4%	0.5%
SC12 Rate I&III	9,607,455	25,867,900	519,373	543,234	557,449	5.4%	5.7%	2.2%
SC12 Rate II	11,771,397	32,290,825	437,289	467,429	479,660	3.7%	4.0%	1.5%
SC13	2,006,488	2,709,976	74,695	75,637	77,616	3.7%	3.8%	2.9%
CECONY Subtotal	$4,581,061,771	$9,593,409,747	$170,115,083	$177,392,719	$182,034,554			
NYPA	$610,714,770	$1,325,324,596	$23,843,918	$24,189,033	$24,821,987	3.9%	4.0%	1.9%
CECONY	4,581,061,771	9,593,409,747	170,115,083	177,392,719	182,034,554	3.7%	3.9%	1.9%
Total	**$5,191,776,541**	**$10,918,734,342**	**$193,959,001**	**$201,581,752**	**$206,856,541**	**3.7%**	**3.9%**	**1.9%**

* Assumes the low income discount level of $54.7 M and $0.547 M Reconnection Fee Waiver.

** Assumes RY1 MAC and NYPA Surcharges. Assumes the same MSC, 18-a and SBC Factors used in the Company's initial filing. Includes supply estimates for RA customers and NYPA.

*** Excludes changes outside of rate case: (1) decreases to above market costs of NUG/public policy contracts and (2) a decrease in PJM OATT costs in RY 2.

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Table 2a
Page 2 of 3

Consolidated Edison Company of New York, Inc.
Case 16-E-0060 - Joint Proposal
Summary of Revenue Increases

Rate Year 3

Levelized

	RY 2 Revenues		RY 3 Increases			Percent Changes - RY 3 Increases over RY 2 Revenues		
Class	Bundled T&D Revenue at 1/1/18 Rates Incl. PPWC & $54.7 M Low Income Credits and $0.547 M Reconnection Fee Waiver *	Total Bill Incl. MAC, MSC, SBC, 18-A and GRT at 1/1/18 Rates **	RY 3 Total T&D Increase Incl. Low Income Discount, PPWC and MAC Change	RY 3 Total Rate Increase Incl. Incremental Low Income Discount, PPWC, and New MAC Charges and NYPA Surcharges Excl. GRT ***	RY3 Total Bill Increase Incl. GRT	**T&D** % Increase Incl. Low Income discount and PPWC and MAC Over **RY3** Revenue @1/1/18 Rate Level	**T&D** % Increase Incl. Incremental Low Income discount and PPWC and New MAC Charges and NYPA Surcharges Over **RY 3** Revenue @1/1/18 Rate Level	**Total Bill** % Increase Over **RY3** Revenue @1/1/18 Rate Level
	(1)	(2)	(3)	(4)	(5)=(4)*GRT	(6)=(3)/(1)	(7)=(4)/(1)	(8)=(5)/(2)
SC1	$2,134,616,387	$3,745,939,689	$90,992,574	$96,187,653	$98,704,595	4.3%	4.5%	2.6%
SC2	401,505,903	661,976,729	15,728,252	16,564,826	16,998,278	3.9%	4.1%	2.6%
SC5 Rate I&III	104,585	213,152	7,851	8,207	8,422	7.5%	7.8%	4.0%
SC5 Rate II	3,434,180	15,717,073	134,785	176,027	180,633	3.9%	5.1%	1.1%
SC6	2,040,449	3,064,049	-37,982	-34,782	-35,692	-1.9%	-1.7%	-1.2%
SC8 Rate I&III	154,246,327	354,388,262	6,086,010	6,746,239	6,922,768	3.9%	4.4%	2.0%
SC8 Rate II	10,202,760	25,650,243	418,381	469,578	481,865	4.1%	4.6%	1.9%
SC9 Rate I&III	1,551,467,268	3,531,546,410	51,476,103	58,014,749	59,532,821	3.3%	3.7%	1.7%
SC9 Rate II	494,752,942	1,425,022,199	4,963,182	8,074,470	8,285,755	1.0%	1.6%	0.6%
SC12 Rate I&III	9,959,224	26,041,270	517,886	571,216	586,163	5.2%	5.7%	2.3%
SC12 Rate II	11,991,241	32,124,606	429,593	496,434	509,424	3.6%	4.1%	1.6%
SC13	2,082,270	2,788,708	74,816	76,949	78,963	3.6%	3.7%	2.8%
CECONY Subtotal	$4,776,403,536	$9,824,472,392	$170,791,451	$187,351,566	$192,253,995			
NYPA	$641,578,627	$1,355,437,316	$23,167,548	$24,848,059	$25,498,258	3.6%	3.9%	1.9%
CECONY	4,776,403,536	9,824,472,392	170,791,451	187,351,566	192,253,995	3.6%	3.9%	2.0%
Total	**$5,417,982,163**	**$11,179,909,708**	**$193,958,999**	**$212,199,625**	**$217,752,253**	**3.6%**	**3.9%**	**1.9%**

* Assumes the low income discount level of $54.7 M and $0.547 M Reconnection Fee Waiver.
** Assumes RY2 MAC and NYPA Surcharges. Assumes the same MSC, 18-a and SBC Factors used in the Company's initial filing. Includes supply estimates for RA customers and NYPA.
*** Excludes changes outside of rate case: (1) decreases to above market costs of NUG/public policy contracts and (2) a decrease in PJM OATT costs in RY 2.

Case 16-E-0060

Consolidated Edison Company of New York, Inc.

Summary of Revenue Neutral Redesigned Rates to Reflect High Tension/Low Tension Differential Adjustments for SC 5 Rate I, SC 12 Rate I and NYPA

At Current 1/1/2016 Rate Level

SC5 Rate I

Rate I	Demand	Blocks	Current 1/1/2016 Rate (1)	Redesigned to Reflect Shift of 5% of Rev. Recovered from Energy to Demand at 1/1/2016	Three-Year Phase-In Before Application of T&D Increase: RY 1 1/3 HT/LT Differential Adjustment	RY 2 2/3 HT/LT Differential Adjustment	RY 3 Full (3/3) HT/LT Differential Adjustment
Summer	LT	0-5 kW	$109.13	$114.51	$114.51	$114.51	$114.51
		> 5kW	$20.51	$21.52	$21.52	$21.52	$21.52
	HT	0-5 kW	$96.61	$101.37	$96.97	$91.72	$87.32
		> 5kW	$18.13	$19.02	$18.18	$17.18	$16.34
Winter	LT	0-5 kW	$70.01	$73.46	$73.46	$73.46	$73.46
		> 5kW	$13.06	$13.70	$13.70	$13.70	$13.70
	HT	0-5 kW	$57.49	$60.32	$55.92	$50.67	$46.27
		> 5kW	$10.67	$11.19	$10.35	$9.35	$8.51
Annualized Charge							
LT			$15.54	$16.31	$16.31	$16.31	$16.31
HT			$13.16	$13.80	$12.96	$11.96	$11.12
HT/LT %			85%	85%	79%	73%	68%
HT/LT % Based on Costs (2)							69%

SC12 Rate I

Rate I	Demand	Blocks	Current 1/1/2016 Rate (1)	Redesigned to Reflect Shift of 5% of Rev. Recovered from Energy to Demand at 1/1/2016	Three-Year Phase-In Before Application of T&D Increase: RY 1 1/3 HT/LT Differential Adjustment	RY2 2/3 HT/LT Differential Adjustment	RY3 Full (3/3) HT/LT Differential Adjustment
Summer	LT	0-5 kW	$133.80	$137.16	$137.16	$137.16	$137.16
		> 5kW	$25.46	$26.10	$26.10	$26.10	$26.10
	HT	0-5 kW	$117.36	$120.31	$114.41	$108.51	$102.56
		> 5kW	$22.33	$22.89	$21.76	$20.63	$19.50
Winter	LT	0-5 kW	$75.12	$77.01	$77.01	$77.01	$77.01
		> 5kW	$14.28	$14.64	$14.64	$14.64	$14.64
	HT	0-5 kW	$58.80	$60.28	$54.38	$48.48	$42.53
		> 5kW	$11.17	$11.45	$10.32	$9.19	$8.06
Annualized Charge							
LT			$18.01	$18.46	$18.46	$18.46	$18.46
HT			$14.89	$15.26	$14.13	$13.00	$11.87
% HT/LT			83%	83%	77%	70%	64%
HT/LT % Based on Costs (2)							65%

NYPA

Rate I	Demand	Blocks	Current 1/1/2016 Rate (1)	Three-Year Phase-In Before Application of T&D Increase: RY 1 1/3 HT/LT Differential Adjustment	RY2 2/3 HT/LT Differential Adjustment	RY3 Full (3/3) HT/LT Differential Adjustment
Summer	LT	Low Tension	$22.69	$23.31	$23.85	$24.47
	HT	High Tension	$20.43	$19.24	$18.20	$17.00
Winter	LT	Low Tension	$22.69	$23.31	$23.85	$24.47
	HT	High Tension	$20.43	$19.24	$18.20	$17.00
Annualized Charge						
LT			$22.69	$23.31	$23.85	$24.47
HT			$20.43	$19.24	$18.20	$17.00
% HT/LT			90%	83%	76%	69%
HT/LT % Based on Costs (2)						67%

(1) Includes temporary credits.

(2) See Exhibit_(ERP-1) Schedule 1.

Case 16-E-0060

Consolidated Edison Company of New York, Inc.

Summary of Revenue Neutral Redesigned Rates to Reflect High Tension/Low Tension Differential Adjustments for SC 8 Rate II and SC 12 Rate II

At Current 1/1/2016 Rate Level

			SC8 II				SC12 II			
				Three-Year Phase-In Before Application of T&D Increase				Three-Year Phase-In Before Application of T&D Increase		
				RY 1	RY 2	RY 3		RY 1	RY 2	RY 3
Rate II	Demand	Time Period (Per kW)	Current 1/1/2016 Rate (1)	1/3 HT/LT Differential Adjustment	2/3 HT/LT Differential Adjustment	Full (3/3) HT/LT Differential Adjustment	Current 1/1/2016 Rate (1)	1/3 HT/LT Differential Adjustment	2/3 HT/LT Differential Adjustment	Full (3/3) HT/LT Differential Adjustment
Summer	LT	M - F, 8 AM - 6 PM	$7.80	$7.80	$7.80	$7.80	$7.12	$7.12	$7.12	$7.12
		M - F, 8 AM - 10 PM	$15.02	$16.30	$17.42	$18.81	$13.87	$15.38	$16.84	$18.30
		All hours - all days	$19.05	$17.78	$16.67	$15.28	$15.23	$13.73	$12.28	$10.84
			$41.87	$41.88	$41.89	$41.89	$36.22	$36.23	$36.24	$36.26
	HT	M - F, 8 AM - 6 PM	$7.80	$7.80	$7.80	$7.80	$7.12	$7.12	$7.12	$7.12
		M - F, 8 AM - 10 PM	$15.02	$16.30	$17.42	$18.81	$13.87	$15.38	$16.84	$18.30
			$22.82	$24.10	$25.22	$26.61	$20.99	$22.50	$23.96	$25.42
Winter	LT	M - F, 8 AM - 10 PM	$9.97	$11.25	$12.37	$13.76	$7.26	$8.77	$10.23	$11.69
		All hours - all days	$6.99	$5.72	$4.61	$3.22	$11.76	$10.26	$8.81	$7.37
			$16.96	$16.97	$16.98	$16.98	$19.02	$19.03	$19.04	$19.06
	HT	M - F, 8 AM - 10 PM	$9.97	$11.25	$12.37	$13.76	$7.26	$8.77	$10.23	$11.69

Annualized Charges								
HT	$14.25	$15.53	$16.65	$18.04	$11.84	$13.35	$14.81	$16.27
LT	$25.26	$25.27	$25.28	$25.28	$24.75	$24.76	$24.77	$24.79
% HT/LT	56%	61%	66%	71%	48%	54%	60%	66%
HT/LT % Based on Costs (2)				70%				66%

(1) Includes temporary credits.

(2) See Exhibit_(ERP-1) Schedule 1.

Case No 16-E-0060
Consolidated Edison Company of New York, Inc.
Factor Used to Allocate Certain Costs Between NYPA and Con Edison Classes
PASNY Allocation
Levelized

	Bundled T&D Revenues at 1/1/2017 Rate Level Incl. Low Income Discount and PPWC	Bundled T&D Revenues at 1/1/2018 Rate Level Incl. Low Income Discount and PPWC	Bundled T&D Revenues at 1/1/2019 Rate Level Incl. Low Income Discount and PPWC
	RY1 (Effective 1/1/2017)	RY2 (Effective 1/1/2018)	RY3 (Effective 1/1/2019)
NYPA	$ 602,169,102	$ 634,558,688	$ 664,746,175
Coned	$ 4,533,553,672	$ 4,750,892,010	$ 4,947,035,571
Total	$ 5,135,722,774	$ 5,385,450,698	$ 5,611,781,746
% NYPA	11.73%	11.78%	11.85%
% Coned	88.27%	88.22%	88.15%
Total	100.00%	100.00%	100.00%

Appendix 20 -- Standby Rate Pilot

Consolidated Edison Company of New York, Inc.

Cases 16-E-0060

Standby Rate Pilot

The Company will implement the Pilot as follows:

Option 1: Targeted 10-Year Exemption or Pilot Rates:

This option is available for up to 50 MW of new or expanded efficient Combined Heat and Power ("CHP") facilities with no less than 1 MW per interconnection and up to 25 MW of new battery energy storage projects with no less than 50 kW of storage per interconnection. The following customer eligibility requirements apply:

(a) To participate in the ten-year exemption from paying standby rates, customers with CHP facilities that are not in operation as of the effective date of the Joint Proposal must have a completed application in the Company's distributed generation ("DG") interconnection queue by December 31, 2019, and the customer must begin commercial operation of the CHP facility or storage system by December 31, 2021.

(b) For customers participating by expanding an existing facility, only the new portion of the facility shall be eligible. The new portion of the facility must be separately metered and billed.

(c) At least 25 MW of the aggregated CHP megawatt capacity shall have the ability to operate in grid-export mode.

Participating customers will remain on non-standby delivery rates for up to 10 years, beginning on the initial date of commercial operation of the project, and will receive shadow billing at the Pilot rates described below during the term of the Pilot and at the then-effective standby rates thereafter. Participants may elect a one-time switch to billing at either: (1) the Pilot rate during the term of the Pilot program; or (2) the then-effective standby rates. The total amount of MW under this Option that can receive the up-to-10-year exemption or be on the Pilot rate described in Option 2 shall be 50 MW of CHP and 25 MW of storage, *e.g.*, if a customer switches from the 10-year exemption to the Option 2 Pilot rate there will be no additional MW that would be eligible for the up to 10-year exemption from standby rates.

CHP facilities participating in this Option shall have the following additional requirements with respect to qualification for the standby rate exemption:

(a) 4-year exemption from standby rates requires an average annual efficiency of 60 percent or greater, but less than 63 percent;

(b) 7-year exemption from standby rates requires an average annual efficiency of 63 percent or greater, but less than 65 percent; and

(c) 10-year exemption from standby rates requires an average annual efficiency of 63 percent or greater and peak efficiency of 65 percent or greater.

(d) All CHP facilities shall meet the NOx emissions standard of 1.6 lbs/MWh or less; and

(e) Participation under this option is not available to technologies that emit criteria air pollutants (*e.g.*, burn fossil fuels) that are not in compliance with local air quality criteria established as part of the Standby/Export Rates Pilot Collaborative as described below.

For items (a)-(c) above, average annual and peak efficiency will be determined using the Higher Heating Value of the fuel. For peak efficiency, power island system efficiency will be measured at the prime mover connections for fuel and electricity, and at the heat recovery device connections for steam and/or hot water. Peak efficiency calculations are performed based on full utilization of electrical and thermal energy.

Option 2: Standby/Export Pilot Rates:

This option is available to standby customers for up to 125 MW as follows: (1) 75 MW is reserved for customers that have qualified under Option 1; and (2) 50 MW is available to standby customers, either new or existing, that do not qualify under Option 1. Applications to participate in the Pilot will remain available until the Pilot is fully subscribed, or until December 31, 2021, whichever is sooner.

The Company will convene a collaborative on or about February 1, 2017 to develop proposed Pilot rates that the Company will file with the Commission with a proposed effective date of January 1, 2018, except that the collaborative will be convened after September 15, 2016, to determine the air quality criteria that will apply to both this Pilot and the SC 11 Bill Credit Proposal such that the air quality criteria will be applicable beginning on January 1, 2017. If the parties cannot reach agreement on this issue in the collaborative, the parties will submit this issue to the Commission for decision.

Once rates are approved by the Commission, participants that choose to be billed at the Pilot rates will be placed on the Pilot rates, with shadow billing at the current standby and/or export rates. The Pilot rates, as described in more detail below, will be designed to test (1) differential levels of standby service by allowing customers to elect a level of Contract Demand; (2) more granular Daily As-Used Demand Charges that include locational and time-varying rates; and (3) payment for locational benefits for SC 11 customers that operate their generation assets to support the distribution system.

The collaborative will develop Pilot rates that will:

(a) develop and test options for customers to assume all or a portion of the reliability risk of their onsite generation by contracting for a lower level of service from the utility, with substantial penalties for non-compliance:

(i) Customers may choose a level of Contract Demand based on the type of service they want from Con Edison;

(ii) Because load-limiting devices are not available for these types of interconnections, significant financial ramifications/price signals will be used to deter customers from exceeding their selected Contract Demand level:

a. Customers will be assessed an Exceedance Surcharge for any kW usage which exceeds the selected Contract Demand amount, unless such exceedance occurs during a scheduled maintenance outage as mutually agreed upon by both the customer and the Company;

b. The Exceedance Surcharge will be set equal to the product of (1) the maximum actual demand less the Contract Demand selected by the customer, in kW; (2) the number of months since the Contract Demand was selected by the customer, up to a maximum of 36; and (3) 1.5 times the applicable Contract Demand rate per kW, in $/kW;

c. If the customer exceeds its Contract Demand, the customer may choose to set a different Contract Demand, provided that the new Contract Demand is higher than the previous amount. Doing so will reset the "timer" in section b.2 above of the Exceedance Surcharge calculation. If the customer elects not to increase its Contract Demand after an exceedance the "timer" used in section b.2 above of the Exceedance Surcharge calculation is not reset.

(b) develop time and locational-variant Daily As-Used Demand pricing, with increased As-Used Demand Charges during network-specific peak hours and lower As-Used Demand Charges outside of network-specific peak hours.

(c) develop and test new export delivery rates for SC 11 customers with onsite generation that actively sell excess generation into the grid and operate their generation for the benefit of the distribution grid.

   a. The collaborative will use data and information from the Con Edison SC 11 buyback delivery rate filing to develop pilot export rates;

   b. Customers may be eligible to participate in the SC 11 Bill Credit Program during the CSRP call hours, depending on the rate to be developed.

Metering and Data Requirements Applicable to Both Exemption and Pilot Customers

Participating customers must provide, at their cost, revenue-grade interval metering (with communications capability and the associated communications service) to measure the output of CHP facilities and/or the charging usage and discharge output of storage projects, as applicable. The metering must be compatible with the Company's metering infrastructure, including compatibility with the Company's meter reading systems and meter communications systems.

Additional Collaborative Activities

The Collaborative will evaluate the reliability, fuel consumption, and efficiency of CHP and storage technologies over the pilot period to provide utilities and stakeholders with data regarding performance and operational needs as follows:

(a) Data reporting shall be in accordance with NYSERDA program protocols, and shall include hourly generation and fuel consumption data, as well as hourly, annual average, and peak efficiency data;

(b) Participants shall provide data related to characterization of output profiles of CHP and storage facilities which may be used for utility planning, operations, and rate design purposes in order to meet the Pilot's goals of (1) providing relevant data to Con Edison and all other interested parties to enable the Company to include the impacts of onsite CHP and storage in its planning, operations, reliability criteria and in the determination of DER hosting capability; and (2) to provide relevant data for the design of future DER compensation;

(c) The Collaborative will seek to leverage existing data from the NYSERDA DG Integrated Data System.

The collaborative will also seek to build consensus on additional data that may be necessary. Pilot participants will also provide certain data to Staff as agreed upon in the collaborative. Pilot participants will engage local New York City permitting agencies to facilitate standardized review and approvals.

Deferral

The Company will defer for future recovery any resulting revenue shortfall from customers who participate in either Option 1 or Option 2.

Appendix 21 -- Gas Revenue Allocation and Rate Design

Consolidated Edison Company of New York, Inc.
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Gas Revenue Allocation and Rate Design

1. Revenue Allocation

Table 1 provides the revenue allocation for each Rate Year, which is explained below. For the first Rate Year, the total increase in the Company's revenue requirement of $35,483,000, less gross receipts tax of $1,228,000, was allocated to firm sales and firm transportation customers in SC 1, 2, 3, 9 and 13 in the following manner:

(a) The Rate Year total delivery revenues at the current rates, including competitive and non-competitive revenues, for each class were realigned for the current low income program based on current total delivery revenues;
(b) The Rate Year total delivery revenues at the current level for SC 1, SC 2 Rate 1, and Rider H were also realigned in a revenue neutral manner to reduce interclass deficiencies and surpluses as indicated by the Company's Gas embedded cost of service ("ECOS") study. For each Rate Year, deficiency and surplus indications have been reduced by one-third;
(c) The Rate Year delivery revenue increase was then allocated to each class by applying the overall Rate Year percentage increase to each class' Adjusted Rate Year delivery revenue as realigned for the low income program and the ECOS surplus and deficiency indications;
(d) The Rate Year delivery revenues for each class were then realigned for the proposed low income program based upon the Adjusted Rate Year delivery revenues;
(e) The total delivery revenue increase by class was determined by subtracting the Adjusted Delivery Revenue at the Rate Year Level from the Total Delivery Revenues at the current rate level;
(f) The RY1 overall percentage rate change for each class was determined by dividing the total RY1 delivery rate change by the total delivery revenue at current rates.

For the second and third Rate Years, the allocation of the total increase in the Company's revenue requirement, less gross receipts tax, was calculated in a similar fashion with the exception of the realignments for the low income program. These realignments were eliminated in Rate Years 2 and 3 in order to reflect the change in the treatment of the low income discounts from a reduced rate to a bill credit.

The overall percentage rate change for each class for Rate Years 2 and 3 were also determined by dividing the total Rate Year delivery rate change by the total Rate Year delivery revenues at current rates. The RY2 delivery revenues at current rates reflect the RY1 non-competitive base tariff rates as well as the RY1 Merchant Function Charge ("MFC") supply and Merchant Function Charge Credit and Collection ("C&C") targets. The RY3 total Rate Year delivery revenues at current rates reflect the RY2 non-competitive base tariff rates as well as the RY2 MFC supply and MFC C&C targets.

A summary of revenue impacts by class, on a delivery-only and total-bill basis for each of the Rate Years, is shown on Table 1a.

2. Rate Design

The rate design process for each Rate Year consisted of the following steps:

- Determining the amount of the revenue increase applicable to competitive charges;
- Determining the amount of the revenue increase to be applied to non-competitive charges; and
- Designing rates for non-competitive charges.

Competitive Delivery Charges

The competitive delivery components include the Merchant Function Charge fixed components, that is, the MFC supply and credit and collections components; the purchase of receivables ("POR") credit and collections component and the billing and payment processing ("BPP") charge, as discussed in Section 3 below. For each Rate Year revised revenue levels for the MFC fixed components and POR credit and collections component were based on percentages of delivery revenue as determined in the Gas ECOS study. There were no revenue changes associated with the BPP charge since it will remain at its current level during the term of the Gas Rate Plan.

Since there was no change in the BPP rate, the amount of the revenue increase attributable to the competitive service charges only reflects the change in the MFC revenues. The change in the MFC revenues for each Rate Year was determined by taking the difference between the MFC target revenues calculated at the Rate Year level and the MFC targets revenues for the previous Rate Year.

Table 2 provides the MFC Supply and MFC C&C Targets for all three Rate Years.

Non-Competitive Delivery Revenues and Rates

The non-competitive delivery revenue increase by class was determined by subtracting the increase in the competitive delivery revenues from the total delivery revenue increase as shown on Table 1.

A summary of the proposed non-competitive rate design methodology, which was used for all three Rate Years, is described below.

The minimum charges (the charge for the delivery of the first three therms or less) in all three Rate Years for SC 2 Rate I, SC 2 Rate II, SC 3, SC 13 and for the corresponding SC 9 rates, will remain at the current levels. The SC 1 minimum charge is increased in all three Rate Years to avoid disproportionally affecting customers using more than 6 therms a month and was set at a level which produces similar bill impacts, on a percentage basis, across all usage ranges.

After considering the amount of the delivery revenue increase attributable to changes in the minimum charges, the remaining non-competitive delivery revenue increase within each class was allocated as follows:

A. For SC 1 and the corresponding SC 9 rate, the balance of the revenue increase was collected through the volumetric rate block (i.e., for all usage over 3 therms per month).

B. For SC 2 Rate I, SC 2 Rate II and the corresponding SC 9 rates, the rate design reflects the change in the applicability criteria. The charges for the first volumetric rate block (i.e., for usage from 4 to 90 therms) within SC 2 were set equal for Rate I and Rate II. The charges for the remaining two volumetric rate blocks within Rate I and Rate II (i.e., for usage from 91 to 3,000 therms and for usage greater than 3,000 therms) were increased, on a uniform percentage basis, based upon the remaining revenue increases for Rate I and Rate II after deducting the change in annual revenues attributable to the minimum charge, the first volumetric (4-90 therms) per therm charge and the air conditioning rates (described below).

C. The charges for the three volumetric rate blocks within SC 3 and the corresponding SC 9 rates (i.e., for usage from 4 to 90 therms, for usage from 91 to 3,000 therms and for usage greater than 3,000 therms) were increased, on a uniform percentage basis, based upon the remaining revenue increase for this class after deducting the changes in annual revenues attributable to the minimum charge and to the air conditioning rates (as explained below).

D. The two volumetric rate blocks within SC 13 and the corresponding SC 9 rates were increased, on a uniform percentage basis, based on the revenue increase for this class.

E. The air-conditioning rates within SC 2 and SC 3 were set equal to the proposed block rates in SC 13 consistent with past practice.

F. Rider G (Economic Development Zone) and Rider I (Gas Manufacturing Incentive) rates were set equal to the applicable SC 2 rates for the first 250 therms per month of usage. The delivery rates for usage from 251-3,000 therms (the "penultimate rate") and in excess of 3,000 therms (the "terminal rate") were increased at the same uniform percentage as their applicable SC 2 rates which maintains the relationship that exists today between the penultimate and terminal delivery rates for Riders G and I and SC 2 delivery rates.

G. Distributed generation rates under Riders H and J were changed as follows:

- The Rider H minimum charges were maintained at their current levels. The per therm rates and the contract demand rate were increased, on a uniform percentage basis, based upon the revenue increase for this class.
- The Rider J Rate I minimum charge and per therm delivery rate, applicable to SC 1 and equivalent SC 9 customers, were increased by the same percentage increases as applied to the SC 1 non-competitive delivery rates.

- The Rider J minimum charge, applicable to SC 3 and equivalent SC 9 customers in buildings with four or less dwelling units, was maintained at its current level. The per therm rate was increased by the same percentage increase as the SC 3 per therm rates.

H. No change was allocated to SC 14, and bypass customers taking firm service under contract rates.

In Rate Year 1, SC 1 and SC 3 low income customers will continue to receive a discount through the base tariff rates. SC 1 low income customers will receive a reduction of $3.00 off the full SC 1 minimum charge. SC 3 low income customers will continue to receive a reduction of $0.4880 per therm in their 4-90 therm block as well as a reduction of $7.25 off the full SC 3 minimum charge.

For Rate Years 2 and 3, the discounts provided to SC 1 and SC 3 low income customers will be reflected on customer bills as credits rather than through reduced rates. As such, low income customers taking service under SC 1 and SC 3 will be charged the same base tariff rates as non-low income customers in those service classes.

Rates in all three Rate Years in the SC 1, SC 2 Rate I, SC 2 Rate II, SC 3 and SC 13 classes still reflect increases to account for the low income funding level of $10.9 million.

3. <u>Competitive Service Charges</u>

Con Edison will continue to unbundle the following competitive service charges:

A. Merchant Function Charge
The Merchant Function Charge, which is applicable to firm full service customers, consists of the following components:

- Supply-Related Component – This component will change each Rate Year in accordance with the rate design targets shown in Table 2.
- C&C Component – This component will change each Rate Year based upon the rate design targets shown in Table 2. Any C&C charges related to gas transportation customers whose ESCOs participate in the Company's Purchase of Receivables program ("POR"), will be included in the POR discount rate, based upon the rate design target shown in Table 2.
- Uncollectible Accounts Expense ("UBs") associated with supply – This component will change each month in the manner described below.
- Gas in Storage Working Capital – This component will continue to be recovered from all firm customers and will change annually as set forth in the Company's gas tariff.

Separate MFC charges will continue to be established for SC 1, SC 2 Rate I, SC 2 Rate

II, SC 3, and SC 13. For the Supply-Related component and for the C&C component, different unit costs will be set for residential and for non-residential classes. At the end of each Rate Year, the supply-related and C&C components of the MFC will be trued up to the Rate Year design targets and any reconciliation amount will be included in the subsequent year's calculation of the MFC.

The charge for UBs associated with supply will continue to be based upon actual supply costs for each month included in the Company's monthly Gas Cost Factor ("GCF"). The UBs associated with supply costs will be included in the MFC. Separate UB factors will be calculated for each of the three GCF groupings and will reflect the overall uncollectible rate of 0.69%, with uncollectible rates of 1.09% for residential customers and 0.41% for non-residential customers.

B. **Billing and Payment Processing Charge**

The BPP Charge for gas will remain at its current level of $1.20 for single service gas customers who purchase both their commodity and delivery from the Company and for retail access customers receiving separate bills from the Company and the ESCO. Dual service customers will pay no more than $0.60 for gas BPP.

C. **Transition Adjustment for Competitive Services**

The Transition Adjustment for Competitive Services ("TACS") reconciles (1) actual revenues received through the C&C component of the POR discount rate with the amount reflected in the discount rate, and (2) any BPP lost revenue attributable to customers migrating to retail access and being billed for their gas use through an ESCO consolidated bill. The reconciliation in (1) above will be based on an allocation of the C&C POR targets as shown on Table 2 for Rate Years 1, 2 and 3.

The TACS applies to firm full service customers and to firm transportation customers and will continue to be assessed through the MRA. The TACS will be recovered at the same cents per therm rate from all firm customers.

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Determination of Total Rate Increase by Service Class for Rate Year 1

	(1)	(2)	(3)	(4)=(1)+(2)+(3)	(5) = (4) * %	(6)	(7)=(4)+(5)+(6)	(8)=(7)-(1)	(9) = (8)/(1)
Service Class	Rate Year Total Delivery Rev. ($)	Re-alignment of Low Income at Current Rate Level ($)	(Surplus)/ Deficiency (a) ($)	Adjusted Rate Year Del Revenue ($)	Rate Increase 3.076% ($)	Re-alignment of Low Income at RY Rate Level ($)	Adj Delivery Rev incl Rate Increase at RY Rate Level ($)	Total Rate Year Increase ($)	Rate Year % Increase
SC No. 1	176,126,837	751,665	4,975,333	181,853,836	5,594,091	(1,744,951)	185,702,976	9,576,138	5.4%
SC No. 2 Rate I	117,115,934	(1,135,260)	(4,715,798)	111,264,877	3,422,671	1,089,100	115,776,648	(1,339,287)	-1.1%
SC No. 2 Rate I, Rider H	6,445,516	(62,479)	(259,536)	6,123,501	188,368	59,939	6,371,807	(73,708)	-1.1%
SC No. 2 Rate II	172,369,440	(1,670,858)	0	170,698,582	5,250,939	1,670,858	177,620,379	5,250,939	3.0%
SC No. 3	641,050,490	2,121,393	0	643,171,884	19,784,910	(1,079,407)	661,877,387	20,826,896	3.2%
SC. No. 13	460,286	(4,462)	0	455,824	14,022	4,462	474,308	14,022	3.0%
Sub-Total	1,113,568,504	0	0	1,113,568,504	34,255,000	0	1,147,823,504	34,255,000	3.1%
SC No. 14 + Firm Bypass	2,848,543								
Total	1,116,417,047								

(a) Represents 1/3 of the (Surplus)/Deficiency Indications

Determination of Non-Competitive Delivery Rate Increase by Service Class for Rate Year 1

	(1)	(2)	(3)	(4)	(5)=(2)+(3)+(4)	(6)=(1)-(5)
		Incremental Competitive Service Revenues				
Service Class	Rate Year Increase ($)	Billing and Payment Processing Component ($)	MFC Fixed Supply Related Revenue ($)	Total MFC Credit & Collection Related Revenue ($)	Total Competitive Related Revenues ($)	Non-Competitive Rate Year Delivery Revenue Increase ($)
SC No. 1	9,576,138	0	(25,092)	195,863	170,770	9,405,368
SC No. 2 Rate I	(1,339,287)	0	(10,409)	991,734	981,325	(2,320,612)
SC No. 2 Rate I, Rider H	(73,708)	0	22,984	72,687	95,671	(169,379)
SC No. 2 Rate II	5,250,939	0	(129,662)	1,546,038	1,416,376	3,834,563
SC No. 3	20,826,896	0	(198,412)	3,052,904	2,854,492	17,972,404
SC. No. 13	14,022	0	(524)	1,897	1,372	12,650
Sub-Total	34,255,000	0	(341,116)	5,861,123	5,520,006	28,734,994
SC No. 14 + Firm Bypass	0					
Total	34,255,000					

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Determination of Total Rate Increase by Service Class for Rate Year 2

	(1)	(2)	(3)=(1)+(2)	(4) = (3) * %	(5)=(3)+(4)	(6)=(5)-(1)	(7) = (6)/(1)
Service Class	Rate Year Total Delivery Rev. ($)	(Surplus)/ Deficiency (a) ($)	Adjusted Rate Year Del Revenue ($)	Rate Increase 7.542% ($)	Adj Delivery Rev incl Rate Increase at RY Rate Level ($)	Total Rate Year Increase ($)	Rate Year % Increase
SC No. 1	189,273,766	4,975,333	194,249,099	14,650,952	208,900,051	19,626,285	10.4%
SC No. 2 Rate I	117,245,226	(4,711,777)	112,533,449	8,487,669	121,021,118	3,775,892	3.2%
SC No. 2 Rate I, Rider H	6,558,187	(263,556)	6,294,630	474,763	6,769,393	211,207	3.2%
SC No. 2 Rate II	178,323,819	0	178,323,819	13,449,811	191,773,630	13,449,811	7.5%
SC No. 3	690,004,297	0	690,004,297	52,042,555	742,046,853	52,042,555	7.5%
SC. No. 13	480,617	0	480,617	36,250	516,867	36,250	7.5%
Sub-Total	1,181,885,912	0	1,181,885,912	89,142,000	1,271,027,912	89,142,000	7.5%
SC No. 14 + Firm Bypass	2,848,543						
Total	1,184,734,455						

(a) Represents 1/3 of the (Surplus)/Deficiency Indications

Determination of Non-Competitive Delivery Rate Increase by Service Class for Rate Year 2

	(1)	(2)	(3)	(4)	(5)=(2)+(3)+(4)	(6)=(1)-(5)
		Incremental Competitive Service Revenues				
Service Class	Rate Year Increase ($)	Billing and Payment Processing Component ($)	MFC Fixed Supply Related Revenue ($)	Total MFC Credit & Collection Related Revenue ($)	Total Competitive Related Revenues ($)	Non-Competitive Rate Year Delivery Revenue Increase ($)
SC No. 1	19,626,285	0	6,320	40,647	46,967	19,579,318
SC No. 2 Rate I	3,775,892	0	27,804	162,976	190,780	3,585,112
SC No. 2 Rate I, Rider H	211,207	0	9,628	21,736	31,364	179,843
SC No. 2 Rate II	13,449,811	0	26,055	221,766	247,821	13,201,989
SC No. 3	52,042,555	0	209,263	881,816	1,091,079	50,951,476
SC. No. 13	36,250	0	180	490	669	35,580
Sub-Total	89,142,000	0	279,250	1,329,431	1,608,682	87,533,318
SC No. 14 + Firm Bypass	0					
Total	89,142,000					

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Determination of Total Rate Increase by Service Class for Rate Year 3

Service Class	(1) Rate Year Total Delivery Rev. ($)	(2) (Surplus)/ Deficiency (a) ($)	(3)=(1)+(2) Adjusted Rate Year Del Revenue ($)	(4) = (3) * % Rate Increase 6.680% ($)	(5)=(3)+(4) Adj Delivery Rev incl Rate Increase at RY Rate Level ($)	(6)=(5)-(1) Total Rate Year Increase ($)	(7) = (6)/(1) Rate Year % Increase
SC No. 1	207,844,158	4,975,333	212,819,491	14,215,666	227,035,157	19,190,999	9.2%
SC No. 2 Rate I	121,105,717	(4,706,682)	116,399,035	7,775,086	124,174,121	3,068,403	2.5%
SC No. 2 Rate I, Rider H	6,912,551	(268,651)	6,643,900	443,791	7,087,691	175,140	2.5%
SC No. 2 Rate II	192,686,070	0	192,686,070	12,870,817	205,556,887	12,870,817	6.7%
SC No. 3	763,772,191	0	763,772,191	51,017,555	814,789,745	51,017,555	6.7%
SC. No. 13	525,255	0	525,255	35,085	560,340	35,085	6.7%
Sub-Total	1,292,845,941	0	1,292,845,941	86,358,000	1,379,203,941	86,358,000	6.7%
SC No. 14 + Firm Bypass	2,848,543						
Total	1,295,694,484						

(a) Represents 1/3 of the (Surplus)/Deficiency Indications

Determination of Non-Competitive Delivery Rate Increase by Service Class for Rate Year 3

	(1)	(2)	(3)	(4)	(5)=(2)+(3)+(4)	(6)=(1)-(5)
		Incremental Competitive Service Revenues				
Service Class	Rate Year Increase ($)	Billing and Payment Processing Component ($)	MFC Fixed Supply Related Revenue ($)	Total MFC Credit & Collection Related Revenue ($)	Total Competitive Related Revenues ($)	Non-Competitive Rate Year Delivery Revenue Increase ($)
SC No. 1	19,190,999	0	6,213	37,766	43,978	19,147,021
SC No. 2 Rate I	3,068,403	0	17,487	127,461	144,948	2,923,456
SC No. 2 Rate I, Rider H	175,140	0	9,949	22,461	32,410	142,731
SC No. 2 Rate II	12,870,817	0	28,265	206,879	235,144	12,635,673
SC No. 3	51,017,555	0	183,074	772,176	955,250	50,062,305
SC. No. 13	35,085	0	200	526	726	34,359
Sub-Total	86,358,000	0	245,187	1,167,268	1,412,456	84,945,544
SC No. 14 + Firm Bypass	0					
Total	86,358,000					

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
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Summary of Rate Increase

Rate Year 1

	Current Revenues at 1/1/16 Rates		RY1 Rate Change	Percent Rate Change	
Service Class	Rate Year Total Delivery Revenue with GRT * (1)	Rate Year Total Bill with GRT ** (2)	Total Rate Change with GRT (3)	Delivery Only (4)=(3)/(1)	Total Bill (5)=(3)/(2)
SC No. 1	$182,440,771	$204,199,955	$9,919,431	5.4%	4.9%
SC No. 2 Rate I	121,314,398	221,015,445	(1,387,298)	-1.1%	-0.6%
SC No. 2 Rate I, Rider H	6,676,580	20,970,813	(76,351)	-1.1%	-0.4%
SC No. 2 Rate II	178,548,675	327,635,962	5,439,178	3.0%	1.7%
SC No. 3	664,031,372	1,111,289,580	21,573,515	3.2%	1.9%
SC. No. 13	476,787	869,491	14,524	3.0%	1.7%
Sub-Total	$1,153,488,583	$1,885,981,247	$35,483,000	3.1%	1.9%
SC No. 14 + contracts	$2,950,660	16,943,314			
Total	$1,156,439,243	$1,902,924,561	$35,483,000	3.1%	1.9%

Notes:
* Includes temporary credit of $40.856 M.
** Includes supply estimate for transportation customers.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 16-G-0061 - Joint Proposal
Summary of Rate Increase

Rate Year 2

	Current Revenues at 1/1/17 Rates		RY2 Rate Change			Percent Rate Change: RY2 Rate Change Only		Percent Rate Change: Total Rate Changes (including cost recovery related to Gate Station Projects)	
Service Class	Rate Year Total Delivery Revenue with GRT (1)	Rate Year Total Bill with GRT* (2)	RY 2 Rate Change with GRT (3)	Cost Recovery for Gate Stations with GRT ** (4)	Total Rate Change with GRT (5)=(4)+(3)	Delivery Only (6)=(3)/(1)	Total Bill (7)=(3)/(2)	Delivery Only (8)=(5)/(1)	Total Bill (9)=(5)/(2)
SC No. 1	$196,057,658	$218,404,908	$20,329,724	$499,107	$20,828,831	10.4%	9.3%	10.6%	9.5%
SC No. 2 Rate I	121,447,493	225,248,450	3,911,227	2,478,866	6,390,093	3.2%	1.7%	5.3%	2.8%
SC No. 2 Rate I, Rider H	6,793,243	21,897,968	218,777	364,512	583,289	3.2%	1.0%	8.6%	2.7%
SC No. 2 Rate II	184,715,246	336,938,572	13,931,875	3,637,588	17,569,463	7.5%	4.1%	9.5%	5.2%
SC No. 3	714,735,218	1,189,988,023	53,907,849	11,297,939	65,205,788	7.5%	4.5%	9.1%	5.5%
SC. No. 13	497,843	905,123	37,549	9,704	47,253	7.5%	4.1%	9.5%	5.2%
Sub-Total	1,224,246,701	1,993,383,045	92,337,000	18,287,716	110,624,716	7.5%	4.6%	9.0%	5.5%
SC No. 14 + contracts	2,950,640	17,300,633		357,434	357,434			12.1%	2.1%
Total	$1,227,197,341	$2,010,683,678	$92,337,000	$18,645,150	$110,982,150	7.5%	4.6%	9.0%	5.5%

Notes:
* Includes supply estimate for transportation customers.
** Assumes recovery of $18 million related to Peekskill and Rye Gate Station Projects. Assumes in service date of November 2017 with recovery in RY2 through MRA at 1.1 c/therm.

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Summary of Rate Increase

Rate Year 3

	Current Revenues at 1/1/18 Rates				RY3 Rate Change			Percent Rate Change: RY3 Rate Change Only		Percent Rate Change: Total Rate Changes (reflects inclusion of Gate Station Projects at Current Revenues)	
Service Class	Rate Year Total Delivery Revenue with GRT (1)	Rate Year Total Bill with GRT * (2)	Cost Recovery for Gate Stations with GRT ** (3)	Rate Year Total Bill including Gate Station Projects with GRT (4)=(3)+(2)	RY3 Rate Change with GRT (5)	Expiration of Cost Recovery for Gate Stations with GRT (6)	Total Rate Change with GRT (7)	Delivery Only (8)=(5)/(1)	Total Bill (9)=(5)/(2)	Delivery Only (10)=(7)/((1)+(3))	Total Bill (11)=(7)/(4)
SC No. 1	$215,293,122	$237,115,440	$499,107	$237,614,546	$19,878,789	($499,107)	$19,379,682	9.2%	8.4%	9.0%	8.2%
SC No. 2 Rate I	125,446,047	226,270,700	2,478,866	228,749,566	3,178,372	(2,478,866)	699,506	2.5%	1.4%	0.5%	0.3%
SC No. 2 Rate I, Rider H	7,160,291	22,186,348	364,512	22,550,860	181,417	(364,512)	(183,095)	2.5%	0.8%	-2.4%	-0.8%
SC No. 2 Rate II	199,591,781	348,310,062	3,637,588	351,947,650	13,332,097	(3,637,588)	9,694,509	6.7%	3.8%	4.8%	2.8%
SC No. 3	791,145,160	1,267,144,876	11,297,939	1,278,442,816	52,845,982	(11,297,939)	41,548,043	6.7%	4.2%	5.2%	3.2%
SC. No. 13	544,080	946,332	9,704	956,036	36,343	(9,704)	26,639	6.7%	3.8%	4.8%	2.8%
Sub-Total	$1,339,180,481	$2,101,973,758	$18,287,716	$2,120,261,474	$89,453,000	($18,287,716)	$71,165,284	6.7%	4.3%	5.2%	3.4%
SC No. 14 + contracts	2,950,633	16,943,157	357,434	17,300,591		(357,434)	(357,434)				
Total	$1,342,131,114	$2,118,916,915	$18,645,150	$2,137,562,065	$89,453,000	($18,645,150)	$70,807,850	6.7%	4.2%	5.2%	3.3%

Notes:
* Includes supply estimate for transportation customers.
** Assumes recovery of $18 million related to Peekskill and Rye Gate Station Projects. Assumes in service date of November 2017 with recovery in RY2 through MRA at 1.1 c/therm.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 16-G-0061

Merchant Function Charge Targets

		Credit & Collections (C&C)		
	Supply MFC	C&C MFC	C&C POR	C&C Total
	$	$	$	$
Rate Year 1	2,607,205	7,643,126	4,769,039	12,412,165
Rate Year 2	2,886,455	8,461,760	5,279,837	13,741,597
Rate Year 3	3,131,643	9,180,537	5,728,328	14,908,865

Appendix 22-- Electric, Gas and Customer Service Reporting Requirements

Consolidated Edison Company of New York, Inc.
Cases 16-E-0060, 16-G-0061
Electric, Gas and Customer Service Reporting Requirements

The following are the Capital Reporting Requirements noted in Section D for Electric, Gas and Customer Service

1. **Electric**

By January 15, 2017, 2018 and 2019, the Company will, for informational purposes, file with the Secretary its most recent projected capital projects and programs list with associated expenditures for electric transmission, substations and distribution operations, electric production, distributed system implementation plan, municipal infrastructure, and shared services allocable to electric, ("Project/Program List") for the upcoming year and the subsequent year. The Company has the flexibility over the term of the Electric Rate Plan to modify the list, priority, nature and scope of its electric capital projects identified in the Project/Program List, subject to the reporting provisions set forth below.

The Company will, for informational purposes, file with the Secretary and submit to the parties in this proceeding, subject to confidentiality concerns, by February 28, 2018, 2019 and 2020:

- a report on its project and/or program expenditures during the prior calendar year for electric transmission, substations and distribution operations, electric production, electric storm hardening, municipal infrastructure, and shared services allocable to electric ("Report").
- A five-year capital budget for electric transmission, substations and

distribution operations, electric production, municipal infrastructure, and shared services allocable to electric.

- This report will include the actual capital and O&M expenditures and deferred amounts, if applicable, during the prior calendar year for AMI, REV demonstration projects, and Distributed System Implementation Plan implementation. The actual expenditures will be presented in aggregate form, separately for capital and O&M expenditures, and for deferred amounts, if applicable, for each of the categories listed above (*i.e.*, AMI, REV demonstration projects, and DSIP implementation), except that for the REV demonstration projects, the actual expenditures will also be presented for each REV demonstration project.

The program budget for the DSIP as set forth in the Company's rate filing is as follows:

	2017	2018	2019
Data Analytics	$1,194	$1,230	$1,260
Load Flow	-	$1,230	$1,260
NRI	$1,194	-	-
Interconnection Portal	$4,509	-	-
DERMS (extend (extend smart grid)	$2,388	$4,919	$5,040
DRMS	$2,388	$2,460	$1,260
DMTS	$3,581	$2,460	$2,520
DMAP (analytics platform)	$3,581	$2,460	$1,260
Customer Portal	-	-	$6,198
Data Exchange	$11,273	$1,127	-
Modernize Protective Relays	$2,865	$5,534	$6,931
Voltage VAR Control (WC)	-	$2,460	$2,520
	$32,972	$23,879	$28,250

The Report will provide (1) a list of all projects and/or programs reflected on the Project/Program List and in the Company's annual capital budgets that were eliminated, with supporting explanation; (2) a list of all new projects and/or programs that were added, with supporting explanation; (3) for all projects and/or programs, including new and eliminated projects and/or programs, the actual amount spent as compared to the forecasted budget amounts. To the extent the amount spent on a project or program varies from the forecasted amount by more than 15 percent, for projects or programs with a forecasted cost greater than $5 million but less than $25 million, or by more than 10 percent for projects or programs with a forecasted cost of $25 million or more, the Company shall provide an explanation of the reasons for the variance.

Quarterly budget meetings with Staff will continue, at which, among other issues, the Company will report on its current expectations in meeting the annual electric capital budget and Net Plant Targets.

2. <u>Gas</u>

The Company will, for informational purposes, file a Gas Capital Expenditures Report with the Secretary and submit it to the parties in this proceeding, subject to confidentiality concerns. The reports will be filed every six (6) months, annual reports (covering the preceding calendar year) will be filed on February 28, 2018, 2019 and 2020; mid-year reports[1] (covering the first six (6) months of the applicable calendar

[1] The Company's mid-year reports will recognize the fact that this Proposal reflects agreement on the annual forecasts in the 2017-2019 Gas Capital Program, rather than monthly expenditures.

year) will be filed on August 31, 2017, 2018 and 2019. The Company has the flexibility over the term of the Gas Rate Plan to modify the list, priority, nature and scope of its gas capital projects identified in the 2017-2019 Gas Capital Program (listed below), subject to the reporting provisions set forth below. The reports will include:

- Summary of Capital Expenditures - formatted similar to the Company's presentation in Exhibit___(GIOP-1); categorize projects into Transmission, Distribution, Technical Operations, Growth and Other; separately track AMI costs during the deployment period; separately identify AMI module costs, tin case meter replacements and the gas portion of allocated common costs; and continue all other current reporting requirements.

- Summary of Capital Additions - broken down by programs and projects.

- For all programs and projects, a comparison of calendar year forecast of expenditures set forth in the 2017-2019 Gas Capital Program vs. calendar year actual expenditures.

- For multi-year programs and projects, a comparison of total expenditures set forth in the 2017-2019 Gas Capital Program vs. actual expenditures, broken down by calendar year (as part of the fourth quarter report).

- Narrative explanation of the reason(s) for any variance in excess of ten (10) percent between the expenditures set forth in the 2017-2019 Gas Capital Program and actual expenditures for any program or project.

- Narrative explanation of the reason and purpose for any new projects or programs exceeding $1 million that were or are going to be undertaken during the current calendar year that were not included in the expenditures set forth in the 2017-2019 Gas Capital Program for that calendar year.

- Summary of expenditures set forth in and the 2017-2019 Gas Capital Program actual capital expenditures for Interference related to:
    - Municipal storm hardening projects.
    - DEP Combined Sewer Overflow projects.

- Summary of capital expenditures related to No. 4/No. 6 oil-to-gas conversions. To the extent necessary, Company will report annually on higher than anticipated capital expenditures, as set forth in Section D.2.b. of the Joint Proposal.

- For Main Replacement programs:
    - For the LPP identified and removed under the risk

prioritization model:
    - Number of miles removed or abandoned by material.
    - The specific location of each section of main removed or abandoned.
- For the LPP removed under all Other capital expenditure programs:
    - Number of miles removed or abandoned by material.
    - The specific location of each section of main removed or abandoned.
- Annual ranking of Total Population LPP by Main Replacement Prioritization Model with segment ID only:
    - Rank of segments expected to be removed in current rate year with segment ID and location.
    - As part of year-end report, identify actual segments removed as compared to expected.
- Actual cost of removal by material, by region.
- The amount of and calculation for any incremental costs the Company recovers through the Safety and Reliability Surcharge Mechanism.

- Rehabilitation of Large Diameter Gas Mains
    - For CISBOT (Cast Iron Joint Sealing Robot)
        - The number of joints rehabilitated
        - The specific location of each section of main that is rehabilitated.
        - Actual cost of CISBOT by region.
        - Results of integrity verification using an internal camera and an external pit at tie-in locations (including assessment for graphitization for cast iron mains) where rehabilitation work is planned
        - Any repairs completed on CISBOT joints
    - For CIPL (Cure in Place Liner)
        - Number of feet rehabilitated by material.
        - The specific location of each section of main rehabilitated.
        - Actual cost of CIPL by material, by region
        - Results of integrity verification using an internal camera and an external pit at tie-in locations where rehabilitation work is planned
        - Any repairs completed on lined mains
    - The Company will also report on the progress of a new NYSEARCH project (M2016-001) to field test aged cured-in-place lined segments as they interact with host steel or cast iron pipe to demonstrate the technology’s long-term performance.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. 2017-2019 GAS CAPITAL PROGRAMS		**Total Dollars ($000)**		
Project /Program Description	**Category Code**	**FY 17**	**FY 18**	**FY 19**
Distribution System Improvement Programs				
Main Replacement Program				
Replace Corroded Steel Mains	Risk Reduction	$98,319	$106,685	$121,291
Replace Cast Iron Mains	Risk Reduction	$141,665	$164,143	$180,150
Cathodic Protection Steel Mains	Risk Reduction	$1,261	$1,284	$1,284
	Sub-Total	**$241,246**	**$272,112**	**$302,725**
Distribution Supply Main Program				
Winter Load Relief	Risk Reduction	$17,163	$17,513	$17,491
Supply Main Planned Reinforcement (CONFIDENTIAL*)	Risk Reduction	$5,558	$6,767	$6,813
Gas System Vulnerability Elimination Program (CONFIDENTIAL*)	Risk Reduction	$11,113	$8,566	$14,943
Emerging Supply Mains Reliability	Risk Reduction	$4,041	$4,129	$4,123
Rehabilitate Large Diameter Gas Mains	Risk Reduction	$4,798	$4,902	$4,895
Replacement of Existing PE and Emergent Water Intrusion	Risk Reduction	$3,029	$3,094	$3,089
SM - Yorktown Upgrade	Risk Reduction	$1,010	$1,032	$1,031
Rehabilitation of the Gas Supply Main to City Island	Risk Reduction	$0	$0	$721
Second Supply to Roosevelt Island	Risk Reduction	$12,123	$0	$0
	Sub-Total	**$58,835**	**$46,003**	**$53,106**
Isolation Valve Installation Program				
Isolation Valves	Risk Reduction	$5,051	$5,161	$5,153
Service Replacement				
Services associated with main work	Risk Reduction	$42,367	$46,066	$50,072
Services Without Curb Valves	Risk Reduction	$1,110	$1,134	$1,132
	Sub-Total	**$43,477**	**$47,200**	**$51,204**
Emergency Replacement of Services				
Leaking Services	Risk Reduction	**$46,854**	**$47,990**	**$47,408**
Distribution System Improvement Programs Total		**$395,463**	**$418,467**	**$459,595**
Transmission Programs and Projects				
Transmission Risk Reduction and Reliability Projects				
Remotely Operating Valves (ROVs)	Risk Reduction	$1,478	$1,478	$3,608
TG – Transmission Pipeline Integrity Main Replacement Program	Risk Reduction	$600	$600	$600
Transmission Main Leaks	Risk Reduction	$2,018	$2,058	$2,056

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. 2017-2019 GAS CAPITAL PROGRAMS		Total Dollars ($000)		
Project /Program Description	**Category Code**	**FY 17**	**FY 18**	**FY 19**
TG – St. Ann's Tee to Hunt Point Downgrade	Risk Reduction	$10,609	$7,742	$0
TG – Yorktown Gate Station Refurbishment	Risk Reduction	$0	$0	$9,291
Newtown Creek Metering Station	Risk Reduction	$3,032	$0	$0
Cortlandt Gate Station Refurbishment	Risk Reduction	$0	$9,093	$0
Greenburgh Yard Refurbishment	Risk Reduction	$2,082	$6,000	$0
Westchester / Bronx Border to White Plains	Risk Reduction	$36,791	$37,526	$38,277
TG - Bronx River Tunnel to Bronx Westchester Border	Risk Reduction	$25,261	$24,810	$24,146
Bronx River Tunnel and Easement	Risk Reduction	$0	$15,485	$12,368
Astoria Transmission Main Reinforcement OTG	Risk Reduction	$10,103	$0	$0
OTG Transmission Main Reinforcement	Risk Reduction	$11,821	$12,078	$7,214
Millennium - Lower Westchester Interconnect	System Expansion	$0	$0	$0
Iroquois-3rd Ward of Queens Interconnect	System Expansion	$0	$0	$15,458
Millennium Pipeline Distribution Regulator Stations (CONFIDENTIAL*)	System Expansion	$0	$0	$0
	Sub-Total	**$103,794**	**$116,870**	**$113,017**
Pressure Control				
PC - Water Proof Manholes	Risk Reduction	$100	$100	$100
PC - Replace Regulators, Valves & Strainer 2 and Larger	Risk Reduction	$500	$500	$500
PC - Unserviceable Equipment	Risk Reduction	$500	$500	$500
PC - Regulator Vent System Refurbishment	Risk Reduction	$456	$463	$462
PC - Uncoated Piping	Risk Reduction	$203	$206	$205
PC - Corroded Gauge Lines	Risk Reduction	$101	$103	$103
PC - Pressure Monitoring / Telemetrics	Risk Reduction	$500	$500	$500
PC - Gridboss / Automated Adaptive Controls	Risk Reduction	$650	$650	$650
	Sub-Total	**$3,010**	**$3,022**	**$3,020**
Transmission Programs and Projects Total		**$106,804**	**$119,892**	**$116,038**
Security				
Tier 2 Security Improvement	Safety/Security	$1,011	$1,032	$1,031
Various Tunnel Properties - Security Improvements	Safety/Security	$0	$0	$310

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. 2017-2019 GAS CAPITAL PROGRAMS		Total Dollars ($000)		
Project /Program Description	**Category Code**	**FY 17**	**FY 18**	**FY 19**
Security Total		**$1,011**	**$1,032**	**$1,340**
Growth Related Programs and Projects				
OTG - #4/6 Conversions NYC	New Business	$55,244	$29,437	$25,150
OTG - #2 Oil Conversions NYC	New Business	$13,422	$13,234	$12,801
OTG - Westchester Area Growth	New Business	$10,102	$10,322	$10,306
OTG - Westchester Conversions	New Business	$17,590	$18,545	$19,684
New Business - Traditional	New Business	$51,904	$53,144	$53,410
OTG – Regulator Stations	New Business	$24,244	$21,669	$12,569
New Business - Regulator Stations	New Business	$7,072	$7,225	$7,208
Growth Related Programs and Projects Total		**$179,577**	**$153,577**	**$141,128**
Technical Operations				
Liquid Natural Gas (LNG)				
LNG - Purchase and Install Vaporizers 1 and 2	Rplmt – Replacement	$3,250	$1,700	$1,400
LNG - Liquefier Instrumentation	Rplmt – Replacement	$0	$0	$1,163
LNG - Purchase and Install Balance of Plant Instrumentation	Rplmt – Replacement	$0	$1,360	$0
LNG - Year Round Liquefier Operation	Rplmt – Replacement	$1,746	$440	$0
LNG - Plant Boil-Off Compressor	Rplmt – Replacement	$0	$0	$750
LNG - Plant Motor Control Center	Rplmt – Replacement	$0	$1,100	$900
LNG - Plant Regeneration Skid	Rplmt – Replacement	$0	$0	$1,300
LNG - Rebuild Turbines 601 and 626	Rplmt – Replacement	$450	$216	$223
LNG - Reconditioning of Plant Structures	Rplmt – Replacement	$845	$0	$0
LNG Plant- Replacement of Dry Chemical Fire Suppression System Zones 5 & 6A	Rplmt – Replacement	$695	$1,200	$0
LNG Plant - Fire Detection and Suppression Compliance Upgrades	Rplmt – Replacement	$5,937	$2,563	$0
	Sub-Total	**$12,923**	**$8,579**	**$5,736**
Tunnels				
Various Tunnel Properties - Steel Replacement Program	Rplmt – Replacement	$0	$996	$0

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. 2017-2019 GAS CAPITAL PROGRAMS		Total Dollars ($000)		
Project /Program Description	**Category Code**	**FY 17**	**FY 18**	**FY 19**
Ravenswood Tunnel - Electric Upgrade	Rplmt – Replacement	$1,323	$0	$0
Ravenswood Tunnel - NYF Gas Main Rollers	Rplmt – Replacement	$626	$918	$500
Ravenswood Tunnel - Feeder Support	Rplmt – Replacement	$627	$918	$500
Bronx River Tunnel - Hoistway	Rplmt – Replacement	$96	$0	$0
Flushing Tunnel - Hoistway	Rplmt – Replacement	$96	$0	$0
Ravenswood Tunnel - Hoistway	Rplmt – Replacement	$0	$0	$100
Hudson Avenue Tunnel - Oil Minder	Rplmt – Replacement	$0	$0	$35
Ravenswood Tunnel - Oil Minder	Rplmt – Replacement	$0	$0	$35
Various Tunnel Properties – Sump Pumps	Rplmt – Replacement	$0	$75	$0
Various Tunnel Properties - Upgrade Cable Radio Systems	Rplmt – Replacement	$0	$0	$926
Various Tunnel Properties - Asphalt Paving	Rplmt – Replacement	$0	$0	$81
First Ave. Tunnel - Flash Tank Replacement	Rplmt – Replacement	$0	$0	$500
Hudson Avenue Tunnel - Floor Meter	Rplmt – Replacement	$0	$0	$65
	Sub-Total	$2,768	$2,907	$2,742
Meters				
Meter Purchases - New Business and Program Replacements	Equipment Purchases	$9,577	$9,521	$9,600
Meter Purchases - #4/6 Oil-to-Gas	Equipment Purchases	$2,100	$1,800	$1,500
Meter Installations – New Business and Program Replacements	New Business	$16,378	$16,481	$16,495
Meter Installations – #4/6 Oil-to-Gas	New Business	$852	$743	$590
	Sub-Total	**$28,907**	**$28,545**	**$28,185**
Picarro Leak Detection Equipment	Information Technology	**$1,200**	**$0**	**$0**
Technical Operations Total		**$45,799**	**$40,031**	**$36,663**
Storm Hardening Projects Total		**$0**	**$0**	**$0**
Gas Work and Asset Management Total		**$21,929**	**$27,149**	**$32,715**

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. 2017-2019 GAS CAPITAL PROGRAMS		Total Dollars ($000)		
Project /Program Description	**Category Code**	**FY 17**	**FY 18**	**FY 19**
Municipal Infrastructure Total		**$82,365**	**$82,055**	**$79,860**
Grand Total- GIOP		**$832,948**	**$842,202**	**$867,339**
Additional IT Projects (See DPS-417 For Clarification)				
IGS Interface with Pipeline Bulletin Boards		$655	$0	$0
Transport customer Info System (TCIS) Daily Delivery Service		$0	$0	$0
AMI - Gas meters		$4,711	$18,551	$44,133
Implementation of new TCIS functionality and Technology Upgrades		$2,790	$1,925	$1,425
MV 90 Upgrade/Replacement Project		$0	$0	$800
Gas Transaction System Replacement/Upgrade		$0	$4,390	$3,400
Additional IT Total		**$8,156**	**$24,866**	**$49,758**
Grand Total - GIOP + Additional IT		**$841,105**	**$867,067**	**$917,098**
		$841,105	**$867,067**	**$917,098**

3. <u>Customer Service:</u>

Beginning January 1, 2017, the Company will, for informational purposes, file a report for each calendar quarter (the "Reporting Period"). Each report will be filed with the Secretary within thirty (30) days after the end of each Reporting Period. The report will include the following:

- Number of residential customers who are subject to a $10 minimum written DPA as of the last date of each month in the Reporting period;
- Number of residential customers who are subject to a payment plan for arrears as of the last date of each month in the Reporting period;
- Number of residential late payment charges assessed as of the last date of each month in the Reporting period;

- Number of residential customers at end of month with arrears greater than 60 days that are supplied by an ESCO as of the last date of each month in the Reporting period;
- Number of residential customers who had meters removed under a replevin action as of the last date of each month in the Reporting period;
- Number of residential customers for which replevin actions were commenced for non-payment of utility bills for service supplied by ESCOs as of the last date of each month in the Reporting period; and
- Number of residential customers who had meters removed under replevin actions for non-payment of utility bills for service supplied by ESCOs during prior 12 months as of the last date of each month in the Reporting period.

Appendix 23 – Replevin Letter

FORM OF NEW YORK CITY PRE-REPLEVIN LETTER

[CON ED LOGO]

Date:

Dear Customer:

Our records indicate that you have a past due amount of ($) for utility service under account number XXXXXXXXXXXXXXX at (SERVICE ADDRESS). Since payment was not made and we could not access the meter in order to terminate service, we have the right to begin legal action to recover our meter.

We have not yet brought legal action against you.

You can avoid possible legal action and additional charges on your account by making prompt payment of the total amount due. To pay by phone, please call 1-888-925-5016. Please have your account number along with your banking information available at the time of your call. To pay by mail, please write your account number, shown above, on your check or money order and mail your payment in the enclosed return envelope. Please ensure that our address appears properly in the envelope window. If you cannot pay the total amount due on your account, depending on your circumstances, we may be able to arrange a deferred payment agreement.

If you do not contact us promptly to either pay the total amount due on your account, or if a deferred payment agreement cannot be arranged, we have the right to begin legal action to recover our meter by applying to the court for an order of seizure. Recovering our meter through an Order of Seizure will result in termination of [electric or gas] service.

If legal action is taken against you, you can anticipate the following:

(1) You will be served a "Notice of Application" and "Attorney Affirmation" which contains supporting documentation about the money you owe to the Company, and informing you of the legal action against you in an attempt to recover our utility meter because you have failed to pay the outstanding balance listed above on your account.

(2) You will have fifteen (15) days from the date the "Notice of Application" and "Attorney Affirmation" are mailed to you to appear at the designated court to respond.

(3) When you appear at the designated court, you will have two options:

a. You must either inform the clerk of the court that you request a voluntary informal conference ("VIC") be scheduled by the court; or
b. You must inform the clerk of the court that you do not wish to participate in a VIC, and

that you request that a hearing with a Judge be scheduled by the court instead.

NOTE ABOUT VOLUNTARY INFORMAL CONFERENCES

Voluntary informal conferences ("VIC") are optional. Selecting to have a VIC means that the court clerk will schedule a date and time for you to discuss your account with a representative from Con Edison at the courthouse. However, a VIC can only be scheduled by the court clerk ***if requested by you***. At the VIC, it may be possible for the Con Edison representative to establish a new deferred payment agreement even if you defaulted on a payment agreement previously. Our records indicate that previously you defaulted on a Payment Agreement on (MMDDYY).

In preparing for a voluntary informal conference with the Company, or alternatively, for a hearing before a Judge, please bring proof of any medical condition necessitating utility service for you or a member of your household, or documentation showing your status, or a family member's status, as elderly, blind, or having a disability. You may also choose to bring proof of unemployment, or financial hardship to support your request for a reduced deferred payment agreement.

(4) If you do not respond to the Notice of Application within fifteen days from the date it was mailed to you, we may present an order of seizure for a Judge's signature. If an order of seizure is signed, the court will likely authorize a City Marshal to gain access to the premises to recover our meter, and a court filing fee, and a Marshal fee, will both likely be added to your account.

As stated above, we have not yet brought legal action against you. **You can prevent legal action from occurring by contacting us immediately** to arrange payment of the balance on your account, or to request a deferred payment agreement.

Keep this letter as a guide in the event that we decide to take legal action against you

Appendix 24 -- Low Income Template

QUARTERLY LOW INCOME REPORT

[Company Name]

LOW INCOME PROGRAM

QUARTER ENDING: 3/31/2016

ITEM DESCRIPTION	CUSTOMERS		
	Electric-only	Gas-only	Combination
1a. Rate discount participants -Total			
1b. Tier 1			
1b. Tier 2			
1c. Tier 3			
1d. Tier 4			
1e. New enrollments			
1f. Exited customers			
2a. Arrears forgiveness participants - Total			
2b. New enrollments			
2c. Exited customers			
2d. Completed			
2e. Defaulted			
2f. Cancelled (customer request)			
2g. Other			
4a. Energy efficiency program participant referrals - Total			
4b. EmPower-NY			
4c. Other			
3. Participant reconnnection fees waived - Total			

ITEM DESCRIPTION	DOLLARS	
	Electric	Gas
5a. Rate discounts - Amount expended		
5b. Over/undercollection		
6a. Arrears forgiveness - Amount expended		
6b. Over/undercollection		
7a. Reconnection fee waivers - Total		
7b. Remaining balance		
8. Average bill - Heating		
9. Average bill - Non-heating		
10a. Total Over/Under Collection		
10b. Regulatory Asset/(Liability) Balance-End of Qua		

ITEM DESCRIPTION	COLLECTION DATA	
	Customers	Dollars
11. Participant Arrears - Total		
12. Termination notices sent to participants		
13a. Participants terminated		
13b. Heat-related		
14a. Participants reconnected		
14b. Due to HEAP/DSS		
14c. Due to DPA		
15a. Active Participant DPAs - beginning of period		
15b. DPAs made		
15c. DPAs reinstated		
15d. DPAs defaulted		
15e. DPAs satisfied		
15f. Active Participant DPAs - End of Period		
15g. Participant DPAs in Arrears >60 days		
16. Participant Uncollectibles		
17. Budget Billing Participants		
17a. Credit Reconciliations (overcollection)		
17b. Debit Reconciliations (undercollection)		

144 FERC ¶ 61,056
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Parts 35, 101 and 141

[Docket Nos. RM11-24-000 and AD10-13-000; Order No. 784]

Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies

(Issued July 18, 2013)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is revising its regulations to foster competition and transparency in ancillary services markets. The Commission is revising certain aspects of its current market-based rate regulations, ancillary services requirements under the *pro forma* open-access transmission tariff (OATT), and accounting and reporting requirements. Specifically, the Commission is revising Part 35 of its regulations to reflect reforms to its Avista policy governing the sale of ancillary services at market-based rates to public utility transmission providers. The Commission is also requiring each public utility transmission provider to add to its OATT Schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service, including as it reviews whether a self-supplying customer has made "alternative comparable arrangements" as required by the Schedule. The final rule also requires each public utility transmission provider to post certain Area Control

Error data as described in the final rule. Finally, the Commission is revising the accounting and reporting requirements under its Uniform System of Accounts for public utilities and licensees and its forms, statements, and reports, contained in FERC Form No. 1, Annual Report of Major Electric Utilities, Licensees and Others, FERC Form No. 1-F, Annual Report for Nonmajor Public Utilities and Licensees, and FERC Form No. 3-Q, Quarterly Financial Report of Electric Utilities, Licensees, and Natural Gas Companies, to better account for and report transactions associated with the use of energy storage devices in public utility operations.

EFFECTIVE DATE: This rule will become effective **[insert date 120 days** after publication in the **FEDERAL REGISTER**].

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION

144 FERC ¶ 61,056
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony Clark.

Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies — Docket Nos. RM11-24-000, AD10-13-000

Order No. 784

FINAL RULE

(Issued July 18, 2013)

Table of Contents — Paragraph Number

1. The Federal Energy Regulatory Commission (Commission) is revising its regulations to enhance competition and transparency in ancillary services markets. The Commission is revising certain aspects of its current market-based rate regulations, ancillary services requirements under the *pro forma* open-access transmission tariff (OATT), and accounting and reporting requirements. Specifically, the Commission is revising Part 35 of its regulations to reflect reforms to its *Avista Corp.*[1] policy governing the sale of ancillary services at market-based rates to public utility transmission providers. The Commission is also requiring each public utility transmission provider to add to its OATT Schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service, including as it reviews whether a self-supplying customer has made "alternative comparable arrangements" as required by the Schedule. Each public utility transmission provider is also required to post certain Area Control Error data on the open access same-time information system (OASIS). Finally, the Commission is revising the accounting and reporting requirements under its Uniform System of Accounts for public utilities and licensees (USofA)[2] and its forms, statements,

[1] *See* 87 FERC ¶ 61,223 (*Avista*), *order on reh'g*, 89 FERC ¶ 61,136 (1999).

[2] *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act,* 18 CFR Part 101 (2012).

and reports, contained in FERC Form No. 1 (Form No. 1), Annual Report of Major Electric Utilities, Licensees and Others,[3] FERC Form No. 1-F (Form No. 1-F), Annual Report for Nonmajor Public Utilities and Licensees,[4] and FERC Form No. 3-Q (Form No. 3-Q), Quarterly Financial Report of Electric Utilities, Licensees, and Natural Gas Companies,[5] to better account for and report transactions associated with the use of energy storage devices in public utility operations.

2. First, the Commission reforms the *Avista* policy governing sales of certain ancillary services to a public utility purchasing the ancillary service to satisfy its own OATT requirements to offer ancillary services to its own customers. As noted in the Notice of Proposed Rulemaking,[6] there is a growing need for ancillary services to support grid functions in the face of potential changes in the portfolio of generation resources and a growing interest of transmission providers to have flexibility in meeting ancillary services needs.[7] There is also interest in third-party provision of ancillary services and

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[3] 18 CFR 141.1 (2012).

[4] 18 CFR 141.2 (2012).

[5] 18 CFR 141.400 (2012).

[6] *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,690 (2012) (NOPR).

[7] *Integration of Variable Energy Resources*, Order No. 764, FERC Stats. & Regs. ¶ 32,331, *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61,232 (2012); and *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322, *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011).

that interest may be unnecessarily frustrated by the *Avista* policy. Comments to the NOPR's proposal to reconsider the *Avista* restrictions generally supported these concepts. As such, and as discussed further below, we conclude that elements of our existing market-based rate regulations can be modified in a manner that continues to limit the exercise of market power, while also enhancing the ability of third parties to compete for the sale of certain ancillary services.

3. Second, we adopt reforms to provide greater transparency with regard to reserve requirements for Regulation and Frequency Response. Under the requirements of the *pro forma* OATT, transmission customers may either purchase Regulation and Frequency Response service at cost-based rates from the public utility transmission provider pursuant to its OATT or self-supply the service, including through purchases from third-parties.[8] With regard to the notion of self-supply, the *pro forma* OATT Schedule 3 merely states that the transmission customer must make alternative comparable arrangements to satisfy is Regulation and Frequency Response Service obligation. In particular, Schedule 3 provides no discussion of the meaning of the term "comparable" as

[8] *See*, *e.g.*, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,716 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002); *pro forma* OATT, Original Sheet Nos. 20-21 and Schedule 3, Original Sheet No. 113.

it relates to reliance on resources with dispatch speed and accuracy characteristics that may differ from those used by the public utility transmission provider. Because the system must be operated reliably at all times, the customer may not decline the transmission provider's offer of ancillary services unless it demonstrates that it has acquired comparable services from another source.[9] In order to clarify the role of resource speed and accuracy in the determination of alternative comparable arrangements, in this Final Rule the Commission requires each public utility transmission provider to add to its OATT Schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service, including as it reviews whether a self-supplying customer has made "alternative comparable arrangements" as required by the Schedule. This statement will also acknowledge that, upon request by the self-supplying customer, the public utility transmission provider will share with the customer its reasoning and any related data used to make the determination of whether the customer has made "alternative comparable arrangements." To aid the transmission customer's ability to make an "apples-to-apples" comparison of regulation resources, the final rule also requires each public utility transmission provider to post on OASIS historical one-minute and ten-minute Area Control Error data as described in the final rule for the most recent calendar year, and update this posting once per year.

[9] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,716.

4. With this information, a transmission customer will be in a position to demonstrate to the public utility transmission provider that the resource(s) it selects for self-supply are comparable to those of the public utility transmission provider. As such, these reforms are necessary to address the potential for undue discrimination against transmission customers choosing to self-supply Regulation and Frequency Response, including through purchases from third-parties. Acknowledging the speed and accuracy of the resources used to provide this service will help to ensure that self-supply requirements of the public utility transmission provider do not unduly discriminate by requiring customers to procure a different amount of regulation reserves than the particular speed and accuracy characteristics of the resources in question justify (i.e., to be comparable, a customer self-supply arrangement that relies on slower, less accurate resources than those of the public utility transmission provider should probably involve a larger reserve requirement than would a purchase from the transmission provider, and vice versa). Moreover, as the Commission has previously stated, because most generation-based ancillary services can be provided by many of the generators connected to the transmission system, some customers may be able to provide or procure such services more economically than the transmission provider can.[10]

[10] *Id.* at 31,718. We note that customers could conceivably procure such services more economically either by paying much less per unit for a larger amount of slower, less accurate resources, or by paying somewhat more per unit for a smaller amount of faster, more accurate resources.

5. Finally, we adopt reforms to our accounting and reporting regulations to add new electric plant and operation and maintenance (O&M) expense accounts for energy storage devices. These reforms are necessary to accommodate the increasing availability of these new resources for use in public utility operations. These reforms are also necessary to ensure that the activities and costs of new energy storage operations are sufficiently transparent to allow effective oversight.

I. Background

6. The Commission has taken numerous steps over the last several decades to foster the development of competitive wholesale energy markets by ensuring non-discriminatory access and comparable treatment of resources in jurisdictional wholesale markets.[11] With regard to ancillary services, the Commission in Order No. 888 delineated two categories of ancillary services: those that the transmission provider is

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[11] *See, e.g.*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,781; *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Montana Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Pub. Citizen, Inc. v. FERC*, 133 S. Ct. 26 (2012); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on reh'g*, Order No. 890-D, 129 FERC ¶ 61,126 (2009); *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

required to provide to all of its basic transmission customers[12] and those that the transmission provider is only required to *offer* to provide to transmission customers serving load in the transmission provider's control area.[13] With respect to the second category the Commission reasoned that the transmission provider is not always uniquely qualified to provide the services and customers may be able to more cost-effectively self-supply them or procure them from other entities. The Commission contemplated that third parties (i.e., parties other than a transmission provider supplying ancillary services pursuant to its OATT obligation) could provide ancillary services on other than a cost-of-service basis if such pricing was supported, on a case-by-case basis, by analyses that demonstrated that the seller lacks market power in the relevant product market.[14] Later, in *Ocean Vista Power Generation, L.L.C.*,[15] the Commission provided guidance regarding such analyses, explaining that as a general matter a study of ancillary services markets should address the nature and characteristics of each ancillary service, as well as

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[12] The first category consists of Scheduling, System Control and Dispatch service and Reactive Supply and Voltage Control from Generation Sources service.

[13] The second category consists of Regulation and Frequency Response service, Energy Imbalance service, Operating Reserve-Spinning service, and Operating Reserve-Supplemental service. Order No. 890 later added an additional OATT ancillary service to this category: Generator Imbalance service. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 85.

[14] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,720-21.

[15] 82 FERC ¶ 61,114, at 61,406-07 (1998) (*Ocean Vista*).

the nature and characteristics of generation capable of supplying each service, and that the study should develop market shares for each service.

7. The Commission subsequently acknowledged in *Avista*[16] that data limitations can impair the ability of sellers to perform a market power study for ancillary services consistent with the requirements of *Ocean Vista*. The Commission therefore adopted a policy allowing third-party ancillary service providers that could not perform a market power study to sell certain ancillary services at market-based rates with certain restrictions.[17] In so doing, the Commission reasoned that the backstop of cost-based ancillary services from transmission providers, in effect, limits the price at which customers are willing to buy ancillary services, thus ensuring that the third-party sellers' rates would remain just and reasonable even without a showing of lack of market power. However, the Commission found that this backstop failed to provide adequate mitigation of potential third-party market power in three situations: (1) sales to a regional transmission organization (RTO) or an independent system operator (ISO), which has no

[16] *Avista*, 87 FERC at 61,882.

[17] These ancillary services included: Regulation and Frequency Response, Energy Imbalance, Operating Reserve-Spinning, and Operating Reserve-Supplemental. The Commission did not extend this *Avista* policy to Reactive Supply and Voltage Control from Generation Sources service, which means that third parties wishing to sell this ancillary service at market-based rates would remain subject to the pre-*Avista* market power screen requirement. The Commission also did not extend the *Avista* policy to Scheduling, System Control and Dispatch service. However, because only balancing area operators can provide this ancillary service, it does not lend itself to competitive supply.

ability to self-supply ancillary services but instead depends on third parties;[18] (2) to address affiliate abuse concerns, sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier; and (3) sales to a public utility that is purchasing ancillary services to satisfy its own OATT requirements to offer ancillary services to its own customers.[19] Therefore, the Commission's *Avista* policy has allowed third-party suppliers to sell certain ancillary services at market-based rates without showing a lack of market power, except under these three circumstances.

8. In its ongoing effort to enhance competitive markets as a means to ensure just and reasonable rates, including those for ancillary services, the Commission has continued to evaluate its *Avista* policy, including, with particular regard to this proceeding, the restriction on the sale of ancillary services by third-parties to a public utility that is purchasing ancillary services to satisfy its own OATT requirements to offer ancillary services to its own customers. The Commission's concern has been to ensure that the cost-based OATT ancillary service rates of public utilities remain a viable backstop or alternative that transmission customers can rely upon instead of the market-based sales from third parties who have not been shown to lack market power. The Commission has

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[18] Subsequently, as the Commission recognized in Order No. 697, most RTOs and ISOs developed formal ancillary service markets, thus rendering this component of the *Avista* policy largely superfluous. *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at n.1194 and P 1069.

[19] *Avista*, 87 FERC ¶ 61,223 at n.12.

reasoned that, if such third-party sellers were permitted to sell to public utilities seeking to meet their OATT ancillary service obligations, the public utility's ability to seek recovery of such purchase costs in OATT rates might lead to increases in those OATT ancillary service rates that may reflect the exercise of market power thus reducing the rates' ability to serve as an effective alternative to purchases from a third-party seller unable to show lack of market power. This would undermine the effectiveness of the mitigation measure that the Commission relied upon in *Avista* to relax the requirement for a market power analysis.[20]

9. However, as the record in this proceeding demonstrates, the restriction on sales of ancillary services at market-based rates to a public utility for purposes of satisfying its OATT requirements has proven to be an unreasonable barrier to entry, unnecessarily restricting access to potential suppliers. In the NOPR, the Commission proposed to address this problem by reforming the *Avista* restrictions, both by modifying the showing an entity must make to establish that it lacks market power and by establishing market power mitigation options in the absence of such a showing.

10. Building off the Commission's action in Order No. 755, which found that accounting for a given resource's speed and accuracy can help ensure just and reasonable

[20] *See Avista Rehearing Order,* 89 FERC at 61,391-92 (stating that the Commission is "able to grant blanket authority for flexible pricing only because the price charged by the third-party supplier is disciplined by the obligation of the transmission provider to offer these services under cost-based rates. This discipline would be thwarted if the transmission provider could substitute purchases under non-cost-based rates for its mandatory service obligation.").

rates and prevent against undue discrimination, in the NOPR, the Commission also proposed to require each public utility transmission provider to include provisions in its OATT explaining how it will determine regulation service reserve requirements for transmission customers, including those that choose to self-supply regulation service, in a manner that takes into account the speed and accuracy of resources used.

11. Finally, the Commission proposed to modify its accounting regulations to increase transparency for energy storage facilities. While the Commission's accounting and reporting requirements associated with the USofA do not dictate the ratemaking decisions of this Commission or State Commissions, these accounting and reporting requirements nevertheless support the rate oversight needs of both this Commission and State Commissions. This information is important in developing and monitoring rates, making policy decisions, compliance and enforcement initiatives, and informing the Commission and the public about the activities of entities that are subject to these accounting and reporting requirements.[21]

II. Discussion

A. The *Avista* Policy

12. As noted above, the Commission's *Avista* policy authorizes the sale of certain ancillary services at market-based rates without showing a lack of market power except under specified circumstances. As relevant here, a third-party may not sell ancillary

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[21] Applicants for market-based rate authority that do not sell under cost-based rates frequently seek and typically are granted waiver of many or all of these requirements.

services at market-based rates to a public utility that is purchasing ancillary services to satisfy its own OATT requirements to offer ancillary services to its own customers. In order to overcome this restriction, a potential seller must provide a market power study demonstrating a lack of market power for the particular ancillary service in the particular geographic market. Based on the record before us, the Commission adopts a number of the reforms to the ancillary services pricing policy proposed in the NOPR and in some instances adopts a number of modifications to those reforms based on the comments received in response to the NOPR.

13. Specifically, this Final Rule allows a resource with market-based rate authority for sales of energy and capacity to sell imbalance services at market-based rates to a public utility transmission provider in the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if those areas have implemented intra-hour scheduling for transmission service. In addition, upon consideration of the comments to the NOPR, this Final Rule also allows a resource with market-based rate authority for sales of energy and capacity to sell operating reserve services at market-based rates to a public utility transmission provider in the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if those areas have implemented intra-hour scheduling for transmission service that supports the delivery of operating reserve resources from one balancing authority area to another. As a result, the only remaining limitation on third-party market-based sales of ancillary services is on sales of Reactive Supply and Voltage Control service and Regulation and Frequency Response service to a public utility that is

purchasing ancillary services to satisfy its own OATT requirements absent a showing of lack of market power or adequate mitigation of potential market power. In that regard, third-party sales of Reactive Supply and Voltage Control service and Regulation and Frequency Response service to public utility transmission providers will be permitted at rates not to exceed the buying public utility transmission provider's OATT rate for the same service. Further, to the extent a transmission provider chooses to procure either Reactive Supply and Voltage Control service or Regulation and Frequency Response service through a competitive solicitation that meets the requirements of this Final Rule, third-party sellers of these services may sell at market-based rates.

14. While the record in this proceeding was insufficient for the Commission to relieve the restrictions for Reactive Supply and Voltage Control service and Regulation and Frequency Response service in the same manner as Imbalance and Operating reserves, we remain interested in exploring the technical, economic and market issues concerning the provision of Reactive Supply and Voltage Control service and Regulation and Frequency Response service. As such, the Commission intends to gather further information regarding the provision of Reactive Supply and Voltage Control service and Regulation and Frequency Response service in a separate, new proceeding.

15. Thus, while we decline to adopt some of the reforms proposed in the NOPR based on the record in this proceeding, we expect that this Final Rule substantially enhances the overall opportunities for third-parties to compete to make sales of ancillary services while continuing to limit the exercise of market power.

16. We will first discuss the market power analyses used to establish authority to sell at market-based rates, followed by a discussion of alternative cost-based mitigation in the event a market participant cannot show it lacks market power for a specific product or service.

1. <u>Use of Market Power Analyses</u>

17. The Commission analyzes horizontal market power[22] for sales of energy and capacity using two indicative screens, the wholesale market share screen and the pivotal supplier screen, to identify sellers that raise no horizontal market power concerns and can otherwise be considered for market-based rate authority.[23] The wholesale market share screen measures whether a seller has a dominant position in the relevant geographic market in terms of the number of megawatts of uncommitted capacity owned or controlled by the seller, as compared to the uncommitted capacity of the entire market.[24] A seller whose share of the relevant market is less than 20 percent during all seasons passes the wholesale market share screen.[25] The pivotal supplier screen evaluates the seller's potential to exercise horizontal market power based on the seller's uncommitted

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[22] 18 CFR 35.37(b) (2012).

[23] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 13, 62. *See also* 18 CFR 35.37(b), (c)(1) (2012).

[24] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 43. Uncommitted capacity is determined by adding the total nameplate or seasonal capacity of generation owned or controlled through contract and firm purchases, less operating reserves, native load commitments and long-term firm sales. *Id.* P 38.

[25] *Id.* PP 43-44, 80, 89.

capacity at the time of annual peak demand in the relevant market.[26] A seller satisfies the pivotal supplier screen if its uncommitted capacity is less than the net uncommitted supply in the relevant market.[27]

18. Passing both the wholesale market share screen and the pivotal supplier screen creates a rebuttable presumption that the seller does not possess horizontal market power with respect to sales of energy or capacity; failing either screen creates a rebuttable presumption that the seller possesses horizontal market power for such sales.[28] A seller that fails one of the screens may present evidence, such as a delivered price test (DPT), to rebut the presumption of horizontal market power.[29] In the alternative, a seller may accept the presumption of horizontal market power and adopt some form of cost-based mitigation.[30]

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[26] 18 CFR 35.37(c)(1) (2012).

[27] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 42.

[28] 18 CFR 35.37(c)(1) (2012).

[29] 18 CFR 35.37(c)(2) (2012). For purposes of rebutting the presumption of horizontal market power, sellers may use the results of the DPT to refine the default relevant geographic market used to perform pivotal supplier and market share analyses and market concentration analyses using the Herfindahl-Hirschman Index (HHI). The HHI is a widely accepted measure of market concentration, calculated by squaring the market share of each firm competing in the market and summing the results. The Commission has stated that a showing of an HHI less than 2,500 in the relevant market for all season/load periods for sellers that have also shown that they are not pivotal and do not possess a market share of 20 percent or greater in any of the season/load periods would constitute a showing of a lack of horizontal market power, absent compelling contrary evidence from intervenors. Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 111.

[30] 18 CFR 35.37(c)(3) (2012).

19. Three of the key components of the analysis of horizontal market power are the definition of products, the determination of appropriate geographic scope of the relevant market for each product, and the identification of the uncommitted generation supply within the relevant geographic market. In Order No. 697, the Commission adopted a default relevant geographic market for sales of energy and capacity.[31] In particular, the Commission will generally use a seller's balancing authority area plus first-tier markets,[32] or the RTO/ISO market as applicable, as the default relevant geographic market. For sales of energy and capacity, the product definitions are well understood: the relevant geographic market is generally the default market described above; and, the uncommitted generation supply is generally identified as all such supply located within the seller's balancing authority area, plus potential uncommitted imports, as determined largely by available transmission capacity in the form of simultaneous import limits.[33] Except in the circumstances set forth in *Avista*, entities seeking to sell ancillary services at market-based rates have been required to provide market power analyses that address the nature and characteristics of each ancillary service, as well as the nature and characteristics of

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[31] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 15.

[32] First-tier markets are those markets directly interconnected to the seller's balancing authority area. *See, e.g.*, Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 232.

[33] Studies of Simultaneous Transmission Import Limits (SIL) quantify a study area's simultaneous import capability from its aggregated first-tier area. SIL studies are used as a basis for calculating import capability to serve load in the relevant geographic market when performing market power analyses.

generation capable of supplying each service.[34] This requirement was based on an assumption that such characteristics might differ from those related to sales of energy and capacity.

a. Reliance on Existing Indicative Screens

20. In the NOPR, the Commission analyzed whether passage of the existing market-based rate screens for sales of energy and capacity can adequately demonstrate lack of market power for sales of ancillary services, based on the relevant characteristics of resources capable of providing each ancillary service. Based on this analysis, the Commission proposed that only the two imbalance ancillary services (Energy Imbalance and Generator Imbalance), and no other ancillary services, could be encompassed by the existing market-based rate screens.[35] The Commission sought comment on both this analysis and the resulting proposal.[36]

21. As discussed in more detail below, commenters addressed both the Commission's ancillary service-by-ancillary service analysis of this issue, and the proposal to apply the existing market power screens to only the imbalance ancillary services.

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[34] *See*, *Ocean Vista,* 82 FERC ¶ 61,114, at 61,406-07 (1998).

[35] NOPR, FERC Stats. & Regs. ¶ 32,690 at PP 18-24.

[36] *Id.* P 24.

i. Application to Imbalance Ancillary Services

Commission Proposal

22. In the NOPR, the Commission stated that resources capable of providing Energy Imbalance and Generator Imbalance do not appear to require any different technical equipment or suffer from any different geographical limitations compared to resources that provide energy or capacity. As a result, the Commission proposed that sellers passing existing market power analyses should be permitted to sell not only energy and capacity in the relevant geographic market(s), but also Energy Imbalance and Generator Imbalance services at market-based rates. The Commission sought comments on, among other things, any unique technical requirements or limitations that might apply to the provision of the imbalance ancillary services that might impact the Commission's proposal to find that passage of the existing market power screens also indicates a lack of market power for imbalance services.[37]

Comments

23. The majority of commenters support the Commission's proposal. AWEA, Beacon, California Storage Alliance, EEI, Electricity Consumers, EPSA, ESA, Iberdrola, Hydro Association, Public Interest Organizations, Powerex, Solar Energy Association, Shell Energy, Southern California Edison, and WSPP support the NOPR proposal to revise the Commission's regulations governing market-based rate authorizations to

[37] *Id.* PP 19-20.

provide that sellers passing existing market-based rate analyses in a given geographic market should be granted a rebuttable presumption that they lack horizontal market power for sales of Energy Imbalance and Generator Imbalance ancillary services in that market.

24. ESA, Electricity Consumers, Beacon, and EEI, among others, agree that there are no special technical requirements or other limitations that apply to the provision of the Energy Imbalance or Generator Imbalance ancillary services.[38] Electricity Consumers and WSPP, among others, argue that the proposed revisions should reduce barriers to ancillary service providers and increase the supply of needed ancillary services. WSPP agrees that the proposal would enable additional sellers of balancing energy to transact with public utility transmission providers in both bilateral markets or a multi-lateral balancing market, and states that it would likely foster sales of balancing energy even outside of the transmission provider market. AWEA contends that the Commission's proposed reforms strike the appropriate balance between reducing barriers to entry and protecting against market power.

25. WSPP and Powerex, with Iberdrola concurring by reference, urge the Commission to clarify that this proposal includes the capacity associated with balancing energy sales, not just the energy.[39] WSPP states that without the underlying capacity, sales of

[38] ESA Comments at 6; Beacon Comments at 5; Electricity Consumers Comments at 3; and EEI Comments at 9.

[39] WSPP Comments at 6; and Powerex Comments at 9-10.

balancing energy could have no firmness and would be of little value in the market, in particular the bilateral market. Further, WSPP contends that the likely market for balancing energy would not differentiate energy and capacity products by OATT Schedules. Rather, sellers would sell "flexible capacity" capable of fulfilling multiple OATT Schedules and operators would look to flexible capacity to support various system stabilizing functions to which the OATT Schedules refer. Thus, WSPP contends that the market would be more efficient if the capacity and energy required to provide OATT services are not required to be unbundled when the natural market for supply would be a bundled "flexible capacity" product.[40]

26. Solar Energy Association states conceptual support for the proposal, but argues that sellers may have market power in certain ancillary services markets even if not in energy or capacity markets, and urges the Commission to police markets that are created due to the adoption of a rebuttable presumption of lack of market power.[41]

27. Two commenters express concern with the NOPR proposal. TAPS objects to the NOPR's preliminary finding that any available unit in a given geographic market is capable of providing energy that helps address imbalances in that market. TAPS contends that significant technical limitations limit the resources that can provide imbalance services absent special arrangements like pseudo-ties, and therefore the first

[40] WSPP Comments at 7.

[41] Solar Energy Association Comments at 4.

tier resources included in the horizontal market power screen are not generally available to provide intra-hour imbalance service. TAPS asserts that Order No. 890-A supports this contention by allegedly finding "that generation outside the control area can provide imbalance service when pseudo-tied and thus subject to within-area dispatch control."[42] TAPS further states that outside organized markets, generators capable of providing imbalance service must have a special relationship with the control area operator in order to supply changing within-the-hour energy needs, without the constraints of hourly transmission scheduling requirements and that even the recently adopted 15-minute scheduling requirement is insufficient, especially when combined with the need to schedule 20 minutes in advance.[43]

28. TAPS asserts that, in non-RTO regions, imbalance service is typically provided by the energy associated with regulation and operating reserves, and thus resources capable of providing imbalance services would necessarily be subject to the same technical requirements as the NOPR described for regulation and operating reserves.[44] TAPS supports this assertion by claiming that Order No. 890 found that "demand costs of providing imbalance service are already being provided under Schedule 3, 5, and 6

[42] TAPS Comments at 11-12.

[43] *Id.* at 11-13.

[44] *Id.* at 12-13.

charges [i.e., Regulation and Frequency Response Service, Operating Reserve-Spinning Reserve Services, and Operating Reserve Supplemental Reserve Services]."[45]

29. TAPS further rejects the Commission's assertion in the NOPR that this proposal is consistent with the decision in Order No. 890-A to base cost-based imbalance charges in the OATT on the incremental cost of the last 10 MW dispatched by the transmission provider for any purpose, without imposing any requirement that this last 10 MW be based on resources with any particular capabilities.[46] TAPS contends that the pricing of OATT imbalance service does not demonstrate the absence of the alleged restrictions described above on the supply of intra-hour energy that allows transmission providers to provide energy imbalance service.

30. Morgan Stanley contends that the existing market power screens are flawed even in their application to energy and capacity products and thus should not be applied to additional products. Morgan Stanley argues that the existing market power screens in some cases fail to assess the full import capability into a given geographic market, and thus the true market size. Morgan Stanley ultimately argues that a revised market power screen "should include any transmission located outside of the relevant market area, but which is interconnected and over which there is transfer capacity."[47] However, Morgan

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[45] *Id.* at 12 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 690).

[46] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 19 (citing Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 309).

[47] Morgan Stanley Comments at 2-5.

Stanley does not state opposition to the idea that a lack of market power in energy and capacity can justify an assumption of equivalent lack of market power in Energy Imbalance and Generator Imbalance services.

Commission Determination

31. The Commission will adopt its proposal with modification. The Commission will allow third-party sellers passing existing market power screens to sell Energy Imbalance and Generator Imbalance services at market-based rates to a public utility transmission provider within the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if those areas have implemented intra-hour scheduling for transmission service.[48] The Commission continues to believe that there are no unique technical requirements or limitations that apply to a resource's provision of Energy Imbalance or Generator Imbalance services. However, the Commission agrees with TAPS that the delivery of Energy Imbalance and Generator Imbalance services may be limited by hourly transmission scheduling practices in place within certain regions and, as such, refines the NOPR proposal as discussed below.

32. Energy Imbalance and Generator Imbalance services are a subset of a broader set of ancillary services offered by a public utility transmission provider to manage system conditions and ensure reliable transmission service. Energy Imbalance and Generator Imbalance services involve the balancing of differences between scheduled and actual

[48] We note that sales of Energy Imbalance and Generator Imbalance services to entities other than a public utility transmission provider remain authorized under *Avista*.

delivery of energy or output of generation over an hour.[49] In comparison, Regulation and Frequency Response service involves the matching of resources to load in a shorter timeframe, requiring automated dispatch at four- or five-second intervals.[50] As a result, resources used to provide Regulation and Frequency Response service must be capable of balancing moment-to-moment fluctuations, whereas resources used to provide Energy and Generator Imbalance can respond at longer time frames within the hour.

33. In practice, public utility transmission providers often have a portfolio of resources, some owned and some purchased from third-parties, from which they provide capacity, energy, and ancillary services. This portfolio typically includes resources with automatic generation control (AGC) equipment capable of handling both moment-by-moment frequency adjustments and longer duration imbalance needs, as well as other capacity and energy resources that may only be capable of addressing longer duration imbalance needs because they are not equipped with AGC. These longer duration resources may include block purchases from third parties that are dispatched or otherwise scheduled at varying timeframes. The relative amount of AGC-controlled and other

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[49] *See pro forma* OATT, Schedules 4 and 9. Under the *pro forma* OATT, imbalances are calculated and charged on an hourly basis. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 722; Order No. 890-A, FERC Stats. & Regs. ¶ 61,297 at P 325 & n.117; *see also* Order No. 764, FERC Stats. & Regs. ¶ 32,331 at P 104. Energy Imbalance and Generator Imbalance services also may be self-supplied by a transmission customer.

[50] *See, e.g.*, Pro Forma OATT, Schedule 3 Regulation and Frequency Response Service – "Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load . . .."

resources used by a public utility transmission provider for intra-hour balancing will depend on the resources available and the public utility transmission provider's operating practices.

34. In the NOPR, the Commission did not separately discuss this range of resources and, instead, preliminarily concluded that there are no unique technical requirements or limitations that distinguish the resources capable of providing energy and capacity from those capable of providing imbalance services. The majority of commenters agree with the Commission's preliminary conclusion, arguing that the set of resources available to follow imbalances over an hour is the same set of resources capable of providing energy and capacity. However, TAPS disagrees, arguing that the set of resources capable of providing imbalance services must have a special relationship with the control area operator in order to supply changing within-the-hour energy needs.

35. We understand TAPS' argument to be that resources used to provide imbalance service must be able to respond to a dynamic four- or five-second signal, which might require special arrangements in order to permit imbalance sales outside of the resource's home balancing authority area such that even the ability to submit transmission schedules on a 15-minute basis would be insufficient to provide intra-hour imbalance energy.[51] We agree that some of the public utility transmission provider's energy imbalance needs are addressed by resources that manage the moment-by-moment difference between load and

[51] TAPS Comments at 13.

resources. We also agree that imbalance service would generally require deliveries on intervals shorter than the current hour. But we do not agree, as explained more fully below, that imbalance services require dynamic dispatch or more sophisticated delivery mechanisms than intra-hour transmission scheduling.

36. Under the *pro forma* OATT, imbalances are calculated on an hourly basis.[52] As a result, any energy deliveries within the hour can be used by a public utility transmission provider (or by a transmission customer) to manage imbalances across the hour. That is, energy deliveries within the hour can be included in the portfolio of resources used to follow imbalance trends across the hour, similar to a public utility transmission provider's decision to redispatch its own internal resources within the hour. While it is true, as TAPS states, that dynamically dispatched resources capable of providing regulation also would be capable of providing imbalance services, it does not follow that resources using intra-hour transmission schedules are incapable of providing imbalance services. As noted above, imbalance service can be provided from a collection of resources so long as they are deliverable within the hour.[53]

[52] *See* Order No. 890, FERC Stats. & Regs. at P 722, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 61,297 at P 325 & n.117; *see also* Order No. 764, FERC Stats. & Regs. ¶ 32,331 at P 104.

[53] The Commission acknowledges that energy purchases scheduled on an hourly basis might enable a public utility transmission provider to use other resources to provide imbalance or other ancillary services more efficiently or precisely. Such hourly sales of energy would not be an indirect sale of ancillary services within the meaning of *Avista*.

37. The question before the Commission here is whether the set of resources considered available to provide energy and capacity in a market power analysis is sufficiently similar to the set of resources capable of providing imbalance services. Based on the record before us in which numerous commenters agree that the resources are sufficiently similar and given that intra-hour transmission schedules are currently being offered by a number of public utility transmission providers, and must be offered by all public utility transmission providers under Order No. 764 on or before November 12, 2013,[54] the Commission finds it appropriate at this time to revise the *Avista* restriction to better reflect current operational realities.

38. With regard to TAPS' additional comments in support of its basic argument, as stated above, just because a public utility transmission provider may have chosen to rely on the energy associated with regulation or operating reserves to meet imbalances, it does not follow that those are the only resources capable of providing imbalance services. Moreover, TAPS' reference to a portion of a passage from Order No. 890 referring to demand costs of providing imbalance energy being recoverable through regulation (Schedule 3) and operating reserve (Schedules 5 and 6) services is not dispositive here. The rate mechanisms used by a public utility transmission provider to recover the cost of

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[54] In order to comply with Order No. 764, public utility transmission providers must allow transmission customers to modify existing schedules as well as create new transmission schedules at intervals not to exceed 15 minutes, on or before November 12, 2013. Order No. 764, FERC Stats. & Regs. ¶ 32,331 at P 91, *order on reh'g*, Order 764-A, 141 FERC ¶ 61,232.

capacity associated with providing Energy Imbalance or Generator Imbalance service do not precisely reflect the technical capabilities of resources available to provide the imbalance services. There is no requirement, in past Commission pronouncements or otherwise, that imbalance services be provided only from resources capable of providing regulation or operating reserves. Indeed, TAPS criticizes the NOPR for asserting the Commission's proposal was consistent with the decision in Order No. 890-A to base cost-based imbalance charges on the incremental cost of the last 10 MW dispatched by the transmission provider for any purpose, without imposing any requirement that this last 10 MW be based on resources with any particular capabilities.[55] We agree with TAPS that the pricing of OATT imbalance services does not necessarily determine the technical capabilities of resources available to provide those services and reject the NOPR's assertion in this regard. Similarly, we find that the pricing of regulation and operating reserve services, whether through Schedules 3, 5, 6 or some other mechanism (such as generator regulation service), do not necessarily determine the technical capabilities of resources available to provide imbalance services.

39. TAPS also cites Order No. 890-A as finding that generation outside a control area can provide imbalance service when pseudo-tied and thus subject to within-area

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[55] *See* NOPR, FERC Stats. & Regs. ¶ 32,690 at P 19 (citing Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 309).

dispatch.[56] The cited passage of Order No. 890-A, however, states that a pseudo-tie arrangement causes a control area to "assum[e] responsibility for ensuring that the load is properly balanced moment-to-moment, for planning for the load, and for providing various other ancillary services including energy or generator balancing service." The Commission made no determination in that passage as to the universe of resources capable, or incapable, of providing imbalance services. Nevertheless, the Commission acknowledges that some public utility transmission providers may choose not to purchase imbalance service from resources that cannot also be dynamically dispatched. While that may inform the relative ability of a resource to find a buyer for its service, it does not define the set of resources from which imbalance services are available, which is the relevant question for market power analyses.

40. We also find the opposing arguments of Morgan Stanley to be beyond the scope of this proceeding. Morgan Stanley does not appear to object to the use of the same market power screens for energy, capacity and imbalance services. Rather, Morgan Stanley argues that the existing indicative screens should be reformulated to include greater transmission imports than are currently assumed. Arguments as to the make-up of the existing market power screens are beyond the scope of this proceeding. The question before us in this proceeding is whether the resources in a given geographic market capable of providing imbalance ancillary services are sufficiently similar to the resources

[56] TAPS Comments at 12 (citing Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 631).

capable of providing energy and capacity that the same market power analysis can apply to both sets of products. Moreover, the Commission already permits applicants to demonstrate that the relevant geographic market is larger or smaller than that default.[57]

41. Accordingly, this Final Rule establishes that sellers found to lack market power in a geographic market, and which are granted market-based rate authority to make sales of energy and capacity, will also be granted market-based rate authority for sales of Energy Imbalance and Generator Imbalance services to public utility transmission providers within the same balancing authority area, or to public utility transmission providers in different balancing authority areas, if those areas allow transmission customers to modify or create transmission schedules within the hour. Because, as explained above, such scheduling practices enable the delivery of within-hour imbalance services from one balancing authority area to another, their use ensures that the first-tier resources included in the existing market power screens can compete with resources in the home balancing authority area, and thus that the existing market power screens can be applied to imbalance services without modification. This finding applies both to sellers that currently have a market-based rate tariff on file and applicants seeking market-based rate authority. For administrative convenience, we make this change to the Commission's ancillary services pricing policy effective as of the effective date of this Final Rule (120 days after publication in the Federal Register), which will result in these changes

[57] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 268.

becoming effective after November 12, 2013, the date by which all public utility transmission providers must offer intra-hour transmission scheduling. As noted above, we acknowledge that some transmission providers already offer intra-hour scheduling. However, rather than performing a transmission provider-by-transmission provider review of current scheduling practices in this rulemaking, the Commission will defer implementation of this change to our ancillary services pricing policy until after the effectiveness of the intra-hour scheduling requirements of Order No. 764, by which time all public utility transmission providers must offer intra-hour scheduling. Thus, as of the effective date, all sellers that have a market-based rate tariff on file as of that date may begin making third-party sales of Energy Imbalance and Generator Imbalance services at market-based rates to a public utility transmission provider that is purchasing Energy Imbalance and Generator Imbalance services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, without having to make a separate showing to the Commission.

42. In response to WSPP, we clarify that this authorization to undertake sales at market-based rates may include both the capacity and the energy associated with providing Energy Imbalance and Generator Imbalance services. Imbalance services are products designed to address differences between scheduled and actual deliveries and withdrawals of energy. As such, they can only be provided by ensuring the availability

of capacity and then increasing or decreasing the energy output from that capacity as necessary to address these differences.[58]

ii. Application to Other Ancillary Services

Commission Proposal

43. In the NOPR, the Commission proposed to allow the existing market-based rate screens to be applied to Energy Imbalance and Generator Imbalance services, but sought comment on whether the characteristics of resources used to provide the other ancillary services would necessitate a market power analysis based on a different geographic market or different set of resources as compared to those analyzed to determine market power for sales of energy and capacity.[59]

44. With regard to Operating Reserve-Spinning and Operating Reserve-Supplemental, the NOPR discussed the technical considerations, such as minimum ramp and start-up rates for off-line resources and the ability for extended operation below fully loaded set point for online resources, that seemed to indicate that fewer resources would be capable of providing these ancillary services as compared to the set of resources capable of providing energy or capacity. With regard to Reactive Supply and Voltage Control from Generation Sources, the NOPR discussed the technical and geographic considerations that generally limit the resources capable of providing this ancillary service as compared

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[58] *See, e.g.*, Order No. 764, FERC Stats. & Regs. ¶ 32,331 at P 240.

[59] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 24.

with the broader set of resources capable of providing energy or capacity. With regard to Regulation and Frequency Response, the Commission discussed the technical requirements, such as automatic generation control (AGC) equipment, that limit the set of resources capable of supplying this ancillary service.[60]

Comments

45. A number of commenters argue for application of the existing market power screens to Operating Reserve-Spinning and Operating Reserve-Supplemental.[61] EPSA argues that operating reserves are merely derivatives of a resource's ability to generate energy.[62]

46. WSPP argues that the same considerations that led the Commission to believe that the rebuttable presumption should be extended to the imbalance ancillary services also apply to the operating reserve ancillary services. WSPP further asserts that all of these ancillary services are widely deliverable and that all generators capable of being redispatched to higher or lower set-points within a scheduling window are capable of providing these ancillary services.[63]

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[60] *Id.* PP 22-23.

[61] EPSA Comments at 6, WSPP Comments at 8 (with Iberdrola supporting by reference), EEI Comments at 3 and 10, Western Group Comments at 3-4, Hydro Association Comments at 7, and Powerex Comments at 7 and 13.

[62] EPSA Comments at 6.

[63] WSPP Comments at 8. Iberdrola supports these WSPP comments by reference.

47. EEI argues that except for variable energy resources, essentially the same set of resources evaluated as competing supply under the existing market power screens possess the required technical capabilities to provide operating reserves.[64] Western Group makes a similar argument, asserting that products in Schedules 3, 5, and 6 (Regulation and Operating Reserves) share operational characteristics of Schedules 4 and 9 (Imbalance services).[65]

48. While Powerex agrees that resources capable of providing spinning and non-spinning reserves may be limited by response time requirements, Powerex argues that the existing market power screens nonetheless can be applied to operating reserve services.[66]

49. With respect to Regulation and Frequency Response, some commenters argue that passage of the existing market power screens indicates lack of market power for that service. For example, while EPSA agrees that the market power of sellers of Reactive Supply and Voltage Control service cannot be gauged by the existing market power screens due to significant technical and geographic impediments, it argues that Regulation and Frequency Response service is merely a derivative of a resource's ability

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[64] EEI Comments at 10.

[65] Western Group Comments at 3.

[66] Powerex Comments at 7 and 13.

to generate energy. Accordingly, EPSA argues that application of the existing market power screens to this ancillary service would be appropriate.[67]

50. Powerex agrees that the existing market power screens could be applied to Regulation and Frequency Response service. Powerex believes that technical improvements such as the dynamic scheduling system adopted by some users of the Western Interconnection facilitate widespread delivery of regulating reserves, thus overcoming any locational requirements for that service, while any technical impediments could be overcome because AGC or equivalent power electronic controls could be added by most market participants if the markets provide correct price signals.[68] WSPP similarly argues that, while not all generators have the AGC equipment needed to provide Regulation and Frequency Response service, installation of this capability is an economic decision and is not such an impediment that it should be treated as a market defining barrier to entry.[69]

51. FTC Staff urges the Commission to recognize that even though a particular resource may not currently have the ability to provide a given ancillary service due to lack of relevant equipment, if such equipment could be installed in a timely fashion in response to high prices, then such resource should be considered a potential competitor

[67] EPSA Comments at 6.

[68] Powerex Comments at 12.

[69] WSPP Comments at 8. Iberdrola supports these WSPP comments by reference.

for purposes of market power analysis. Accordingly, FTC Staff suggests that the Commission revise its market power analysis to incorporate as existing market participants those potential entrants that are likely to enter a given ancillary service market (i.e., install needed equipment such as AGC) rapidly and profitably should market prices justify such entry.[70]

52. EEI argues that, before extending application of the existing market power screens to Regulation and Frequency Response, the Commission should separate this service into two separate ancillary services: primary frequency control and secondary frequency control. EEI argues that secondary frequency control, which it labels as Regulation, is a prime candidate to be extended the rebuttable presumption (i.e., to be subject to the existing market power screens).[71]

53. Two parties filed comments opposing the application of existing market power screens to non-imbalance ancillary services. Southern California Edison and TAPS state that they agree with the NOPR's reasoning as to why the existing market power screens cannot be applied to non-imbalance ancillary services.[72] Remaining commenters did not address the question of applying the existing market power screens to non-imbalance ancillary services.

[70] FTC Staff Comments at 6-8.

[71] EEI Comments at 10-11.

[72] Southern California Edison Comments at 1-2; and TAPS Comments at 9-10.

Commission Determination

54. Upon consideration of the comments to the NOPR, and as discussed more fully below, the Commission will allow third-party sellers passing existing market power screens to sell Operating Reserve-Spinning and Operating Reserve-Supplemental services at market-based rates to a public utility transmission provider within the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if those areas have implemented intra-hour scheduling for transmission service that supports the delivery of operating reserve resources from one balancing authority area to another. Commenters have persuaded us that to the extent there are technical requirements and limitations associated with operating reserves, they do not materially distinguish resources capable of providing energy and capacity from those capable of providing operating reserves. As with the imbalance services, however, the Commission finds that the delivery of operating reserves from one balancing authority area to another may be limited by hourly scheduling practices in place within certain regions, which could impact the assumption in the existing market power screens that first-tier resources are able to compete with home balancing authority area resources. Therefore, the Commission will allow third-party sellers passing existing market power screens to sell these services to public utility transmission providers to the extent within-hour transmission service scheduling practices, including intra-hour transmission scheduling mandated by Order No. 764, support the delivery of operating reserves from one balancing authority area to another.

55. In contrast, the Commission affirms the preliminary finding in the NOPR that the set of resources capable of providing Regulation and Frequency Response service and Reactive Supply and Voltage Control service would differ significantly from the broader set of resources capable of supplying energy and capacity. Accordingly, the *Avista* restrictions will remain in place for sales of those services to public utility transmission providers at market-based rates. As noted below, the Commission will establish a new proceeding to further explore the technical, economic and market issues concerning the provision of Reactive Supply and Voltage Control service and Regulation and Frequency Response service.

Operating Reserve Services

56. Operating Reserve-Spinning and Operating Reserve-Supplemental are products designed to serve load temporarily in the event of contingencies. As such, sellers must ensure the availability of capacity sufficient to address a contingency event and, if the contingency occurs, energy must be supplied from that capacity. While the NOPR preliminarily found that the operating reserve products appeared to require the availability of resources with relatively fast ramping capabilities, and in the case of off-line resources used for operating reserve-supplemental, relatively fast start-up capabilities as well,[73] comments to the NOPR argue otherwise.

[73] *See* NOPR, FERC Stats. & Regs. ¶ 32,690 at P 22.

57. Many comments to the NOPR make the case that the flexibility and response time requirements associated with operating reserve services are not so significant that the universe of resources that can provide these services is meaningfully different than the universe of resources used to assess energy and capacity market power. While traditional generation scheduling practices only require the resources that provide energy and capacity to be able to change output levels once an hour, the record in this proceeding indicates that most resources can change output levels on shorter time scales. In other words, most conventional resources can change output in response to contingency events on a time scale shorter than the typical hourly scheduling window, even if in the past they have only been selling hourly block energy and capacity. Therefore, the Commission will allow third-party sellers passing existing market power screens for energy and capacity for a given market to also sell Operating Reserves-Spinning and Operating Reserves-Supplemental services at market-based rates to a public utility transmission provider within the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if within-hour transmission scheduling practices in those areas support the delivery of operating reserves from one balancing authority area to another.[74]

[74] As with Energy Imbalance and Generator Imbalance services, we clarify that the authorization to undertake sales at market-based rates may include both the capacity and the energy associated with providing Operating Reserve-Spinning and Operating Reserve-Supplemental services.

58. We note that our approach for market-based sales of operating reserves differs slightly from the reforms adopted above for sales of imbalance services. We have found above that the existence of 15-minute scheduling in a region renders the set of resources capable of supplying imbalance services substantially similar to the set of resources capable of providing energy and capacity so that the same market power screens can be applied to both sets of services. This may not be the case in all circumstances for potential sellers of operating reserves and, therefore, we require such entities to explain in their market-based rate applications for such authority how the scheduling practices in their regions support the use of operating reserves. For example, while 15-minute scheduling might be sufficient for Operating Reserve-Supplemental because this service only requires designated resources to be available within a short period of time,[75] 15-minute scheduling by itself may not be sufficient for Operating Reserve-Spinning, which requires designated resources to be available immediately.[76] The Commission recognizes that unlike the imbalance services, operating reserve services are targeted only at addressing contingency events, and some regions such as WECC may have already developed within-hour capacity tagging and scheduling practices intended to support the

[75] *See pro forma* OATT, Schedule 6 "Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time."

[76] *Id.* Schedule 5 "Spinning Reserve Service is needed to serve load immediately in the event of a system contingency."

use of operating reserves across multiple balancing authority areas.[77] These are the types of region-specific practices that sellers seeking authority to sell operating reserves to public utility transmission providers should describe in their market-based rate applications. Thus, as of the effective date of this Final Rule, both sellers that have a market-based rate tariff on file as of that date and applicants seeking new market-based rate authority must satisfactorily make the above showing and receive Commission authorization before making sales of Operating Reserve-Spinning and Operating Reserve-Supplemental to a public utility that is purchasing Operating Reserve-Spinning and Operating Reserve-Supplemental to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.

Regulation and Reactive Power Services

59. The Commission affirms the preliminary finding in the NOPR that the more stringent technical and geographic considerations associated with the regulation and reactive power ancillary services suggest that they are not simple combinations of basic energy and capacity products. Most commenters addressing this issue agree that the set of resources considered by the existing market power screens would differ too

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[77] *See, e.g.*, WECC Regional Business Practice INT-018-WECC-RBP-0, Tagging Protocols, at WR5.1 and WR5.2, defining capacity e-tags for, respectively, spinning reserves and non-spinning reserves as "product(s) that can be activated through the adjustment of a capacity e-tag." *Available at* http://www.wecc.biz/library/Documentation%20Categorization%20Files/Forms/AllItems.aspx?RootFolder=%2flibrary%2fDocumentation%20Categorization%20Files%2fRegional%20Business%20Practices&FolderCTID=0x01200015E7900DB2E794468FDE06D520B95C07 .

significantly from the set of resources that would be considered by market power analyses designed specifically for Reactive Supply and Voltage Control service.

60. While some commenters do argue that the existing market power screens are adequate for Regulation and Frequency Response service, we are not persuaded by their arguments on the record here. We continue to believe that significant technical requirements, such as the need for AGC equipment, limit the set of resources capable of supplying this ancillary service. While we agree in principle with FTC Staff's comments that potential competitors could be viewed as existing competitors for purposes of market power analysis if it is known that they can install needed equipment rapidly and profitably in response to appropriate price signals, the record does not conclusively support the notion that such equipment upgrades (e.g., to install AGC equipment in an existing generator) can be accomplished in such a manner. Although Powerex asserts that AGC or equivalent power electronic controls could be added by most market participants if the markets provide correct price signals, and WSPP asserts that the addition of AGC is an economic decision, we are not persuaded based on the limited information in the record before us.. Also, the record indicates that third-party sellers of Regulation and Frequency Response service might need to enter into or facilitate special arrangements between neighboring balancing authorities, such as dynamic scheduling or pseudo-tie arrangements, in order to make sales outside of their home balancing authority area.

61. Accordingly, because the record before us does not support a modification at this time, the *Avista* restrictions will remain in place for sales of Regulation and Frequency

Response and Reactive Supply and Voltage Control services to a public utility transmission provider that is purchasing these ancillary services to satisfy its own OATT requirements to offer ancillary services to its own customers. However, the Commission intends to gather more information regarding this issue in a separate, new proceeding that will further explore the technical, economic and market issues concerning the provision of Reactive Supply and Voltage Control service and Regulation and Frequency Response service. Such proceeding will consider, among other things, the ease and cost-effectiveness of relevant equipment upgrades, the need for and availability of appropriate special arrangements such as dynamic scheduling or pseudo-tie arrangements, and other technical requirements for provision of Regulation and Frequency Response and Reactive Supply and Voltage Control services.

b. Optional Market Power Screen

Commission Proposal

62. In the NOPR, the Commission proposed a new optional market power screen solely applicable to ancillary services, together with a limited new reporting requirement that would provide potential sellers of ancillary services with the information needed to develop market power analyses using that optional market power screen.[78] Specifically, the optional market power screen for an ancillary service would compare the amount of capacity in MWs (or, as applicable, MVARs) that a potential seller can dedicate to

[78] NOPR, FERC Stats. & Regs. ¶ 32,690 at PP 25-30.

providing the ancillary service in the relevant geographic market with the buyer's aggregate requirement for that ancillary service, taking into account any historical locational requirements (e.g., locational requirements due to such things as binding transmission constraints or the geographic limitations of Reactive Supply). Using this optional market power screen, sellers whose available capacity is no more than 20 percent of the relevant aggregate requirement for an ancillary service would receive a rebuttable presumption that they lack horizontal market power for the ancillary service in question.

63. In order to provide sellers with information as to the buyer's aggregate requirement for an ancillary service, the Commission proposed to require each public utility transmission provider to publicly post on its OASIS the aggregate amount (MW or MVAR, as applicable) of each ancillary service that it has historically required, including any geographic limitations it may face in meeting such ancillary service requirements. For example, a transmission provider may report that it has historically maintained 100 MW of Regulation and Frequency Response reserves for its balancing authority area and 100 MVAR of Reactive Supply and Voltage Control in each of two submarkets within its balancing authority area.

Comments

64. Some commenters support the optional market power screen on the basis that it provides a practical alternative to performing a traditional market power analysis, given the data constraints associated with the latter. WSPP, for example, states that the optional market power screen is a constructive response to the disconnection between

regulatory market power study requirements and the incapability of market participants to perform those studies due to lack of data.[79] WSPP states that it strongly supports the Commission's proposal that public utility transmission providers be required to post the information needed for sellers to prepare the optional market power screen if the rebuttable presumption applicable to the imbalance ancillary service is not extended to all ancillary services.[80]

65. Public Interest Organizations argue that the optional screen is similar in intent to a *de minimis* capacity threshold and, as such, can remove the barrier of a burdensome market power analysis for smaller entities.[81] The Solar Energy Association asserts that the optional market power screen likely will broaden the number of participants in the markets for certain ancillary services.[82] Electricity Consumers similarly argues that the optional market power screen should reduce barriers to ancillary service providers and increase the supply of ancillary services in a timely and cost-effective manner.[83]

66. However, there was no consensus among the commenters supporting the proposed optional market power screen regarding the necessary granularity of the associated reporting requirement. Some commenters, such as WSPP and Shell Energy, argue that

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[79] WSPP Comments at 12.

[80] *Id*. at 10.

[81] Public Interest Organizations Comments at 6.

[82] Solar Energy Association Comments at 5.

[83] Electricity Consumers Comments at 3.

postings should reflect a transmission provider's annual peak requirements for ancillary services, rather than annual averages. WSPP argues that posting an annual average would tend to understate requirements for higher periods, thereby skewing screen results in the direction of violations.[84] Similarly, Shell Energy states that relying on annual peaks is preferable to annual averages because it better reflects the amounts that transmission providers need to procure. Shell Energy further argues that postings of annual peak values are preferable to postings of seasonal or quarterly values, which Shell Energy claims would be burdensome for transmission providers and suppliers.[85]

67. Conversely, the ESA, Beacon, and California Storage Alliance recommend that public utilities provide seasonal and time-of-day requirements (if any) for each ancillary service versus a single average annual amount and note that this is consistent with the type of data provided by RTOs/ISOs in the open wholesale markets.[86]

68. Some commenters oppose the optional market power screen, arguing that it would yield too many false positives because it does not measure a seller's ability to supply relative to the total potential supply of the overall market. EPSA, for example, argues that the optional screen would routinely result in false-positive indications of market

[84] WSPP Comments at 11.

[85] Shell Energy Comments at 8.

[86] ESA Comments at 7; Beacon Comments at 6; and California Storage Alliance Comments at 4.

power.[87] EPSA states that if the Commission decides to use a threshold test, it should compare the subject generator to total product capability, not merely the quantity demanded.[88] EEI similarly argues that the optional screen likely will result in many suppliers failing the 20 percent threshold.[89] EEI contends that there are alternatives that would refine the test to be more applicable and useful in promoting robust participation in competitive ancillary services markets in bilateral regions. EEI offers as an example requiring transmission providers to report on its OASIS in the aggregate its historical demand and its historical ability to supply the relevant ancillary services. EEI offers that if the Commission decides to pursue optional screen it should have a technical conference.[90]

69. Powerex claims that the optional market power screen does not appear workable in certain respects and is likely to result in too many false positives.[91] Powerex argues that establishing a test that is overly restrictive, and that a majority of sellers will not be able to satisfy, will create a significant administrative burden that will continue to pose an obstacle to the development of competitive markets for ancillary services.[92] Powerex

[87] EPSA Comments at 6.

[88] *Id*. at 7.

[89] EEI Comments at 16.

[90] EEI Comments at 15.

[91] Powerex Comments at 16.

[92] *Id*. at 17.

asserts that when using market shares as a metric of market power, the proper measurement is a seller's ability to supply relative to the total potential supply of the overall market.[93]

70. Morgan Stanley argues that the optional market power screen does not provide a complete picture of an entity's market power and that it is more relevant to compare the amount of supply a seller controls to the total supply available and the total market demand, than it is to compare it to a single buyer's requirements.[94] Morgan Stanley claims that a seller actually could have greater market power even if it only can serve a small portion of the buyer's aggregate requirements if the buyer has no other viable options for procuring the remaining portion of its ancillary service needs.[95]

71. Other commenters oppose the optional market power screen on the basis that its need and usefulness is unclear. For example, TAPS argues that the usefulness of the optional screen is uncertain, particularly given the acknowledged data limitations. TAPS further argues that one cannot be confident that the proxy would provide a meaningful screen for market power.[96]

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[93] *Id*. at 19.

[94] Morgan Stanley Comments at 6.

[95] *Id*. at 7.

[96] TAPS Comments at 14.

72. The California PUC states that is sees no need for alternative methodologies and further argues that a 20 percent threshold is too high for ancillary services.[97] The Hydro Association also states that it does not see a need at this time for the Commission to develop alternative market screens.[98]

Commission Determination

73. The Commission will not adopt the optional market power screen for ancillary services as proposed in the NOPR. As suggested by EEI, ESPA and others, the fact that the proposed optional screen would not consider the full amount of competing supply available to a buyer likely means that the screen may result in so many false positive indications of potential market power that it would provide little benefit to the effort to foster competition in ancillary service markets.

74. The comments also indicate that establishing the reporting requirements associated with the optional market power screen would not be a trivial task, particularly given the lack of consensus regarding the granularity of information needed. The Commission believes that the costs of developing and imposing this new reporting requirement on transmission providers might not be justified, particularly in light of the other actions taken in this Final Rule. The need for the proposed optional screen, and its associated reporting requirement, is significantly reduced because this Final Rule, as explained

[97] California PUC Comments at 5-6.

[98] Hydro Association Comments at 8.

above, will permit sellers to apply the existing market power screens to imbalance and operating reserve ancillary services. As such, the Commission has determined not to adopt the optional market power screen and its associated reporting requirement.

2. Alternative Mitigation

75. In the NOPR, the Commission proposed to permit sellers unable or unwilling to perform the market power study for ancillary services to propose price caps at or below which sales of Regulation and Frequency Response, Reactive Supply and Voltage Control, Operating Reserve-Spinning, or Operating Reserve-Supplemental service would be allowed where the purchasing entity is a public utility transmission provider purchasing ancillary services to satisfy its OATT requirements to offer ancillary services to its own customers.[99] Such a price cap would have been based on one of the two possible OATT ancillary service rate caps discussed below and, as in *Avista*, the Commission proposed that sales under these price caps would only be permitted in geographic markets where the seller has been granted market-based rate authority for sales of energy and capacity. In addition, a seller unable to perform a market power study for ancillary services could rely on competitive solicitations meeting certain minimum requirements in order to make sales in geographic markets where the seller has been granted market-based rate authority for sales of energy and capacity.

[99] NOPR, FERC Stats. & Regs. ¶ 32,690 at PP 33-40.

a. Use of Price Caps

Commission Proposal

76. In the NOPR, the Commission proposed two cost-based mitigation measures as alternatives to the prohibition adopted in *Avista* with regard to sales to a public utility transmission provider that is purchasing ancillary services to meet its OATT requirements to offer ancillary services to its own customers. Sales of ancillary services at or below either alternative would be permitted. Under the first, third parties would be permitted to sell to a public utility transmission provider at rates not to exceed the buying public utility transmission provider's existing OATT rate for the same ancillary service. Under the second option, third parties could propose to sell a given ancillary service to a public utility transmission provider at rates not to exceed the highest public utility transmission provider OATT rate within the relevant geographic market for physical trading of the ancillary service in question. The Commission proposed that the seller (or group of sellers) would file with the Commission a proposal that defines the scope of a contiguous geographic region that both encompasses the service territory(ies) of the public utility transmission provider whose OATT ancillary service rate will form the basis for the price cap, and within which trading of the ancillary service in question is physically possible.

i. Single OATT Rate Cap Option

Comments

77. There was a range of support for the establishment of a rate cap at the buyer's OATT rate for the same ancillary service. TAPS and Southern California Edison support

this proposal outright as an option to enable ancillary service sales.[100] EEI states that while the Commission should primarily rely on existing market power analyses and screens to allow third-parties to sell certain ancillary services at market-based rates, cost-based mitigation measures are also appropriate in certain seller-specific circumstances. EEI states that these two alternative options should be included in any Final Rule. EEI contends that this flexibility should encourage an increased number of participating sellers in bilateral markets, provide options for transmission providers to meet obligations, create market efficiencies, and potentially lower prices.[101]

78. WSPP states that it supports inclusion of this option to enhance flexibility in the sale of ancillary services, but with reservations. WSPP's reservations essentially concern whether existing OATT ancillary services rates provide appropriate price signals. WSPP contends that because reserve sales are from the same units as energy sales, mitigation price caps that fail to take opportunity costs into account during peak periods are unduly low.[102] Separately, WSPP asks the Commission to clarify that for the single OATT rate cap there is no filing with the Commission as a prerequisite to the sale.[103] AWEA and Solar Energy Association either support the proposal or do not state opposition to it.[104]

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[100] TAPS Comments at 15-18 and Southern California Edison Comments at 6.

[101] EEI Comments at 18-19.

[102] WSPP Comments at 15.

[103] *Id.* at 14.

[104] AWEA Comments at 3 and Solar Energy Association Comments at 6.

Iberdrola supports WSPP's and AWEA's comments by reference.[105] Electricity Consumers state that they do not object to the proposed alternatives provided that they are in fact promulgated as alternatives to the proposed revisions to the market power analysis.[106]

79. Although ESA, Beacon, and California Storage Alliance all support this proposal, they each argue that for this mitigation measure to be successful in fostering robust competitive markets, the Commission must ensure that cost-based schedules for ancillary services, in particular Regulation and Frequency Response, are compared on an "apples-to-apples" basis taking into account resource performance.[107]

80. Some commenters oppose this price cap proposal unless the cap can be raised in some way. For example, Shell Energy argues that a cap based on the buyer's OATT rate would not produce prices high enough to entice competitive supply. Instead, Shell Energy suggests establishment of a price cap set at 200 percent of the buyer's OATT rate for the ancillary service in question.[108] Similarly, EPSA asserts that cost-based price caps systematically fail to represent the true value of capacity products and will fail to allow a full range of economic tradeoffs in the bilateral markets. EPSA states support for the use

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[105] Iberdrola Comments at 3.

[106] Electricity Consumers Comments at 4.

[107] ESA Comments at 8-10; Beacon Comments at 7-9; and California Storage Alliance Comments at 5-6.

[108] Shell Energy Comments at 8-9.

of price caps as a last resort, and only if they reflect the seller's lost opportunity costs as represented by energy transactions during a recent historical period.[109] Powerex makes similar arguments, favoring the use of energy price indices to represent lost opportunity costs. Failing that, Powerex argues that a component for transmission costs for remote suppliers should be added to any OATT-based price cap.[110]

81. ENBALA argues that a cost-based cap limited to the buying utility's OATT rate might be too restrictive and lead the Commission to scrutinize more agreements than necessary, but ENBALA states that "Reactive Supply and Voltage Control service should be excluded from the regional price cap, being priced by the buying utility's OATT rate to reflect the geographic limitations of the ancillary service."[111]

Commission Determination

82. As one option available to sellers, the Commission will permit market-based sales of Regulation and Frequency Response service and Reactive Supply and Voltage Control service to public utility transmission providers at rates not to exceed the buying public utility transmission provider's OATT rate for the same service.[112] We find that a price cap based on the buying public utility transmission provider's OATT rate for the same

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[109] EPSA Comments at 9-10.

[110] Powerex Comments at 25-29.

[111] ENBALA Comments at 2-4.

[112] We do not apply this mitigation option to the other OATT ancillary services because this Final Rule allows sales of those services at market-based rates for any seller that has market-based rate authority for energy and capacity.

ancillary service would produce a just and reasonable rate, and do so in a manner that is administratively simple. As discussed in the NOPR,[113] because the buying public utility transmission provider's OATT ancillary service rates have already been found to be just and reasonable, it is reasonable to find that any third-party sales of the same ancillary service to that buyer at or below that buyer's own approved rates for that service would also be just and reasonable. Accordingly, we will not require sellers to make a separate showing as to the justness and reasonableness of such rates and will allow sellers to make third-party sales of such services at rates as discussed here as of the effective date of this Final Rule.

83. Allowing the sale of ancillary services below the purchasing public utility transmission provider's OATT rate is a reasonable extension of the mitigation measure relied upon by the *Avista* policy itself. As discussed earlier,[114] the *Avista* policy sought to protect buyers of third-party ancillary services from potential exercise of market power by ensuring that they would continue to have access to cost-based ancillary services from transmission providers, in effect limiting the price at which customers are willing to buy ancillary services from third-parties. The result of the *Avista* mitigation measure is an implicit soft cap on the price at which third-party ancillary services could be offered to

[113] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 34.

[114] *See supra* P 7.

non-transmission provider customers. The price cap proposal adopted here extends this concept to transmission providers by creating an explicit price cap at the same level.

84. While a few commenters opine that a cap based on the buyer's OATT rate would not produce prices high enough to entice competitive supply, the Commission finds that, given the reforms adopted elsewhere in this Final Rule, it is appropriate to take the more conservative step of adopting a price cap based on the buyer's OATT rate for sales of Regulation and Frequency Response service and Reactive Supply and Voltage Control service to public utility transmission providers. This measure can be implemented quickly and easily with few administrative burdens on either the Commission or the industry. Alternative proposals by commenters would require more complicated design, analysis, and oversight to ensure that they achieve just and reasonable rates.

85. With respect to the arguments of ESA, Beacon, and California Storage Alliance that for this mitigation measure to be successful, the Commission must ensure that cost-based schedules for ancillary services are compared on an "apples-to-apples" basis taking into account resource performance, the Commission addresses this issue below in sub-section B of this Final Rule.

ii. Regional OATT Rate Cap Option

Comments

86. Some commenters, such as ESA, Beacon, and the California Storage Alliance, support the regional OATT rate cap option on the basis that it is a reasonable

approximation of the cost of entry.[115] ENBALA also expresses support for a regional cost-based rate cap, arguing that it provides an adequate alternative to the current formal market power requirement.[116] EEI and Electricity Consumers also express support for a regional OATT rate cap but offer no specific recommendations.[117]

87. Southern California Edison states that it supports a cap based on the highest OATT rate within the geographic market as long as it is capped at the lesser of (a) the highest OATT rate in the market or (b) three times the median OATT rate in the relevant geographic market. Southern California Edison explains that it proposes this modification to protect against having a small balancing authority area with an extremely high outlier rate setting the cap.[118]

88. Other commenters criticize the highest OATT rate cap proposal. Some parties, such as WSPP, EPSA, and Powerex, argue that setting caps based on cost-based rates would not allow sellers to recover foregone opportunity costs associated with energy sales and thus would fail to create any incentives for sellers to enter ancillary service markets. They argue that this is particularly true for short-term ancillary service sales, given that opportunity costs vary materially for hourly, daily, monthly, and seasonal

[115] ESA Comments at 10; California Storage Alliance Comments at 7; and Beacon Comments at 9.

[116] ENBALA Comments at 2.

[117] EEI Comments at 18-19; and Electricity Consumers Comments at 4.

[118] Southern California Edison Comments at 6-7.

periods, but these variations are not reflected in OATT rates and therefore would not be reflected in the cap.

89. For example, Powerex contends that any alternative price cap must be high enough to create economic incentives for potential sellers to forego other opportunities, namely, energy sales.[119] Powerex argues that setting price caps based on transmission providers' cost-based rates in many instances will not allow sellers to recover the foregone opportunity costs associated with energy sales and that this is particularly true for short-term ancillary service sales.[120] Powerex states that short-term energy prices in the CAISO and other Western markets are frequently several-fold higher than Northwest transmission providers' OATT rates for ancillary services.[121]

90. Similarly, EPSA argues that a price cap should include a seller's lost opportunity costs, represented by energy transactions during a recent historical period. EPSA states that it is critically important to include lost opportunity costs, in order to allow a generator to rationally choose between producing energy and not producing energy.[122]

91. WSPP asserts that the Commission's observation that the OATT rate could be indicative of the cost of new entry appears speculative. WSPP contends that a cost-based rate may reflect a fully or substantially depreciated unit, rather than the cost of new

[119] Powerex Comments at 26.

[120] *Id*.

[121] *Id*. at 27.

[122] EPSA Comments at 9-10.

construction.[123] WSPP also argues that because reserve sales are made from the same resources as energy sales, mitigation price caps that fail to take opportunity costs into account during peak periods are unduly low.[124]

92. Other commenters raise concerns about setting the geographic boundaries for a regional OATT rate cap. Shell Energy asserts that identifying the region in which an ancillary service can be physically traded can be difficult and recommends that the Commission, rather than sellers, identify the relevant trading regions and post that information on the Commission's website.[125] TAPS argues that a regional price cap would invite gerrymandering and provide no assurance that the resulting cap is a more reasonable approximation of the cost of new entry.[126] TAPS argues that significant physical constraints limit the provision of ancillary services over a geographic area.[127] TAPS contends that the regional OATT rate cap proposal is not defensible as either a cost-based or market-based rate and is at odds with the physical limitations on the provision of ancillary services in non-RTO regions.[128] TAPS contends that another regional transmission provider's higher rate (i.e., the highest regional rate) does not bear

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[123] WSPP Comments at 15.

[124] *Id*. at 15.

[125] Shell Energy Comments at 9.

[126] TAPS Comments at 22.

[127] *Id.* at 20.

[128] *Id*. at 2.

any relationship to either a third-party supplier's or the purchasing transmission provider's cost of supply.[129]

Commission Determination

93. The Commission will not adopt the NOPR proposal that would allow sellers to propose a price cap equal to the highest OATT rate within a specified region. Based on the comments received, the Commission concludes that use of a regional OATT rate cap would be inadequate to ensure that third-party sellers' rates remain just and reasonable. In the NOPR, the Commission suggested that this mitigation proposal might be justified on a cost basis in that the highest regional rate may be a reasonable approximation of the cost of new entry into the region in question.[130] However, the record developed in this proceeding does not support such a conclusion at this time.

94. We also share commenters' concerns associated with defining appropriate regions for purposes of setting regional price caps. The Commission is concerned that sellers would have an incentive to "gerrymander" or "cherry-pick" regional definitions to ensure inclusion of a high-cost ancillary service provider. In light of the other actions taken in this Final Rule, the Commission believes it would not be productive to undertake the analyses necessary to establish seller-specific regions for various ancillary services.

[129] *Id*. at 19.

[130] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 36.

b. Competitive Solicitations

Commission Proposal

95. The NOPR proposed to allow applicants to engage in sales to a public utility that is purchasing ancillary services to satisfy its OATT requirements to offer ancillary services to its own customers where the sale is made pursuant to a competitive solicitation that meets the following guidelines: (1) transparency – the competitive solicitation process should be open and fair; (2) definition – the product or products sought through the competitive solicitation should be precisely defined; (3) evaluation – evaluation criteria should be standardized and applied equally to all bids and bidders; (4) oversight – an independent third-party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection;[131] and (5) competitiveness – adequate seller interest to ensure competitiveness.

Comments

96. Commenters generally support the proposal to permit competitive solicitations as an alternative to performing a market power study.[132] EEI, for example, expresses support for competitive procurement as an option for long-term resource planning.[133]

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[131] *See, e.g.*, *Allegheny Energy Supply Co. LLC*, 108 FERC ¶ 61,082 (2004).

[132] EPSA Comments at 8-9; EEI Comments at 19-20; ESA Comments at 10-11; Beacon Comments at 9-11; California Storage Alliance Comments at 7; and ENBALA Comments at 4.

[133] EEI Comments at 19-20.

EPSA states that the Commission's proposed guidelines for competitive solicitations conform to general principles that EPSA has advocated for such processes.[134]

97. Some commenters object to certain aspects of the Commission's proposal. Most criticism is directed at the proposed requirement for independent third-party oversight of competitive solicitations. WSPP, for example, expresses support for competitive solicitations as a means of mitigating potential market power concerns but opposes the proposed oversight by an independent third party. WSPP argues that such oversight is unnecessary, and that the required filing is ample to demonstrate whether or not the solicitation yielded sufficient competition.[135] Shell Energy agrees that third-party oversight of competitive solicitations is unnecessary, arguing that this requirement would hinder short-term procurement of ancillary services and make the solicitation process unfeasible except for long-term transactions.[136]

98. However, Morgan Stanley contends that it is not clear that the Commission's competitive solicitation proposal would protect against market power. Morgan Stanley contends that a competitive solicitation only demonstrates lack of market power if it is robust enough to attract offers that, in aggregate, are significantly in excess of the quantity sought. Morgan Stanley states that it is not clear how a competitive solicitation

[134] EPSA Comments at 8-9.

[135] WSPP Comments at 17-18.

[136] Shell Energy Comments at 10.

could help buyers looking to purchase such services on a short-term basis, although it might for the long-term provision of ancillary services.[137]

Commission Determination

99. The Commission adopts the NOPR proposal to allow applicants to engage in market-based sales of ancillary services to a public utility that is purchasing ancillary services to satisfy its OATT requirements where the sale is made pursuant to a competitive solicitation that meets the requirements specified in the NOPR as numerated above, except as modified below. The Commission has relied on the use of competitive solicitations to mitigate affiliate abuse concerns when affiliates seek to enter into transactions pursuant to market-based rate authority.[138] In that context, the Commission has adopted guidelines for independent, third-party review of competitive solicitations. The requirements proposed for sales of ancillary services to public utility transmission providers are based on these guidelines, which the Commission concludes are reasonable to adopt here with one exception. Upon review of comments, we have decided to partially eliminate the requirement that an independent third-party design and administer the solicitation and evaluate bids prior to the company's selection.

100. As proposed, the independent third-party review requirement would apply to all competitive solicitations. However, the record does not support imposing a requirement

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[137] Morgan Stanley Comments at 8-9.

[138] *See Boston Edison Co. Re: Edgar Electric Energy Co.*, 55 FERC ¶ 61,382 (1991); *Allegheny*, 108 FERC ¶ 61,082.

for independent third-party review when none of the parties participating in a competitive solicitation is affiliated with the buying public utility transmission provider. If no affiliate of the buyer participates in the solicitation, there is no concern regarding preferential treatment and, therefore, no need for review by an independent third party. As commenters suggest, requiring an independent third-party reviewer could discourage the use of competitive solicitations as it would add to the cost and time needed to procure ancillary services. Some public utility buyers may have a short-term, unexpected need for ancillary services and therefore need to act quickly to fill this need. In such cases, the buyer itself will have to conduct the solicitation, with very limited time for independent review. The Commission therefore revises the NOPR proposal to require independent third-party review of competitive solicitations only when the buyer solicits offers from one or more of its affiliates.

101. However, the Commission emphasizes that any buyer seeking to procure ancillary services from unaffiliated sellers through a competitive solicitation will need to demonstrate compliance with the four other requirements: transparency, definition, evaluation, and competitiveness. In this regard, we reject Morgan Stanley's assertion that the competitiveness requirement can only be met where a solicitation attracts offers that, in aggregate, are significantly in excess of the quantity sought. We believe there may be multiple methods of demonstrating adequate competitiveness, and we will review such proposals on a case-by-case basis. This will help ensure that any ancillary services procured in this manner are purchased at a competitive market price. At the same time, these requirements will not hinder buyers' flexibility to design solicitations to meet their

specific needs. This demonstration must be made through a filing under section 205 of the Federal Power Act, submitted by the seller to the Commission prior to commencement of service under the third-party ancillary service sales agreement that results from the competitive solicitation. To be specific, the third-party seller will need to submit both the actual sales agreement and a narrative description of how the buyer's competitive solicitation meets the requirements of this Final Rule. This narrative description will help demonstrate that exercise of market power was not a factor in the negotiation of the sales agreement, and therefore that the resulting rate is just and reasonable.

B. Resource Speed and Accuracy in Determination of Regulation and Frequency Response Reserve Requirements

Commission Proposal

102. The Commission proposed in the NOPR to require that each public utility transmission provider submit provisions for inclusion in its OATT that take into account the speed and accuracy of regulation resources in determining its Regulation and Frequency Response reserve requirements. Among other things, this would allow customers choosing to self-supply this service with faster responding or more accurate resources to self-supply with a lower volume of regulation capacity, or vice versa. The Commission stated that it expects to evaluate each proposed determination of regulation reserve requirements on a case-by-case basis. It also stated that each description of how the public utility will adjust its regulation capacity requirement must provide enough detail that an entity wishing to self-supply may compare the resources it is considering

using with the resources that the public utility is using. The Commission sought comment on how speed and accuracy should be taken into account.[139]

Comments

103. A majority of commenters[140] generally support the NOPR proposal to require each public utility transmission provider to submit provisions for inclusion in its OATT that take into account the speed and accuracy of regulation resources in determining its Regulation and Frequency Response reserve requirements. Electricity Consumers, Hydro Association, Morgan Stanley, California PUC, and EPSA highlight the benefits of increased transparency, to which EPSA adds that lack of transparency is an impediment to competitive compensation outside of ISOs/RTOs and contributes to a lack of a discernible market value for speed and accuracy. Other commenters, including Public Interest Organizations, Iberdrola, Morgan Stanley, and FTC Staff cite avoidance of undue discrimination, comparable treatment, and the potential that the NOPR proposal will encourage innovation and new entry, as reasons for supporting the proposal. Solar Energy Association supports taking into account the speed and accuracy of regulation

[139] NOPR, FERC Stats. & Regs. ¶ 32,690 at PP 47-54.

[140] These commenters include Beacon, California Storage Alliance, ESA, Hydro Association, Solar Energy Association, Public Interest Organizations, California PUC, AWEA, Morgan Stanley, EPSA, TAPS, FTC Staff, Electricity Consumers, and Iberdrola.

resources when establishing the rates that may be charged for those services, with faster and more accurate resources priced accordingly.[141]

104. Hydro Association supports the idea of "pay for performance" standards that recognize the difference between accurate fast-responding resources versus resources that ramp more slowly and respond less nimbly, and agrees with the Commission that a case-by-case evaluation of each proposed determination is more appropriate than imposing a mandatory methodology. Similarly, California PUC states that transparency should act as a deterrent against discrimination, but cautions that the Commission should avoid an overly prescriptive methodology that may dictate the amount of regulation resources that are needed.

105. Several other commenters, including Beacon, ESA, California Storage Alliance, and Morgan Stanley, encourage the Commission to require transmission providers to provide an explanation of how they set their regulation reserve requirements. ESA, Beacon, and California Storage Alliance propose five elements of an explanation that each transmission provider should be required to provide about how it sets its regulation reserve requirement,[142] as well as a list of specific information that each transmission

[141] Solar Industry Association Comments at 3.

[142] The five elements are: (1) a description of the calculation; (2) the metric which is used to set the requirement; (3) the average performance of the existing Regulation assets; (4) the speed and accuracy of the units currently in place (including ramp-rate and accuracy); and (5) sufficient data for a third party to reproduce the results, including posting ACE data on its OASIS reporting. ESA Comments at 12-13; Beacon Comments at 12; and California Storage Alliance Comments at 6.

provider should make available.[143] Morgan Stanley also urges the Commission to require public utility transmission providers to provide demonstrations of equivalent treatment for their own or their affiliate's requirements to ensure that there is no undue discrimination, and to establish a process for market participants to challenge and resolve the speed and accuracy assumptions and requirements that public utility transmission providers publish.[144] Beacon and ESA also state that ideally the Commission would require each utility to develop a conversion formula or chart that specifies how much capacity a transmission customer must self-supply given a certain ramp-rate and accuracy.

106. ESA, Beacon, Public Interest Organizations, California Storage Alliance, and AWEA advocate extending the requirement of accounting for speed and accuracy in regulation service to public utilities meeting their own needs, including via third-party suppliers, not simply to transmission customers choosing to self-supply.[145] AWEA argues that holding more reserves than needed may result in rates that are not just and reasonable.[146] ESA, Beacon, Public Interest Organizations, and California Storage

[143] Each entity proposes a bulleted list of nine items including generation capacity available to provide regulation, rates, costs, accuracy and CPS scores, and representative ACE data. ESA Comments at 13; and Beacon Comments at 12-13.

[144] Morgan Stanley Comments at 10.

[145] Beacon and Public Interest Organizations support ESA's comments regarding third party sales of regulation.

[146] AWEA Comments at 4.

Alliance state that third party sales to a public utility that is purchasing ancillary services to satisfy its own OATT requirements to offer ancillary services to its own customers represents the most significant potential market for sales of ancillary services in non-RTO/ISO regions. Public Interest Organizations agree, arguing that neither the current rules nor the NOPR encourage transmission providers to improve the speed and accuracy of their owned or contracted frequency regulation resources, and that allowing generators to be displaced from providing frequency regulation will enable them to operate at a more stable output, which also can lower energy market prices. Public Interest Organizations contend that the existing OATT Schedule 3 rate treatment is no longer adequate to incorporate emerging technologies, and encourage the Commission to require that OATT Schedule 3 rates incorporate Order No. 755's framework of an objective accuracy and performance determination, and that the amount of frequency regulation transmission customers are required to procure or self-supply takes into account the speed and accuracy capability of the ancillary service provider's technology.[147]

107. Parties that support extending the proposal to public utility transmission providers meeting their own needs also recommend that the Commission consider performance-based rate treatment for public utility investments and contracts with third-party ancillary service providers that allow the public utility to reduce the total capacity and cost of

[147] Public Interest Organizations Comments at 8.

providing regulation service while maintaining the same level of reliability.[148] They argue that the potential benefits to ratepayers could justify allowing a performance-based incentive rate adder that public utility transmission providers could recover through rates, and that if the public utility can demonstrate that it will be able to reduce the total capacity and cost of providing regulation service and maintain the same degree of reliability, such treatment should result in public utilities improving the performance of their regulation fleet and in turn reducing expenses for frequency regulation, ultimately resulting in lower costs.

108. TAPS asks the Commission to state explicitly that the NOPR's proposal to account for the speed and accuracy of customer self-supplied regulating resources includes demand resources and to state that such a finding would be consistent with OATT Schedule 3 and Order No. 755.[149]

109. EEI opposes the NOPR proposal. It contends that it is premature to require each transmission provider to include provisions in its OATT explaining how it will determine Regulation and Frequency Response requirements, and requests that the Commission defer this proposal pending experience with secondary frequency control (i.e., regulation) in the ISOs and RTOs following the issuance of Order No. 755.[150] EEI requests that the

[148] *See* comments of ESA, Beacon, Public Interest Organizations, and California Storage Alliance.

[149] TAPS Comments at 27.

[150] EEI Comments at 22-26.

Commission recognize the material differences between primary and secondary frequency control resources in the final rule. It argues that it is also premature to adopt requirements regarding primary frequency control, and recommends that the Commission encourage each balancing authority to continue investigating the role of various types of resources, and allow the industry to maintain its efforts to understand the relationship and interdependencies between primary and secondary frequency response.

110. EEI contends that the assumption that faster responding technologies are necessarily more efficient than traditional methods of frequency regulation has not been substantiated. EEI explains that industry is still exploring frequency response, including current and historical primary and secondary control response performance, and that for system reliability it is important to maintain a balanced portfolio of resources including inertial response, governor response, and secondary frequency control (or regulation response). It further explains that, although OATT Schedule 3 groups primary and secondary frequency control into a single service, the nature of these services are distinct. With regard to secondary frequency control (regulation), EEI claims that the benefits from resources that ramp more quickly for purposes of secondary frequency control may be offset by a lack of capability to sustain that response, or to provide automatic primary frequency control.

Commission Determination

111. The Commission will adopt the NOPR proposal with modification. Rather than requiring OATT Schedule 3 to include a description of how resource speed and accuracy will be taken into account in determining Regulation and Frequency Response reserve

requirements, we will require each public utility transmission provider to add to its OATT Schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service, including as it reviews whether a self-supplying customer has made "alternative comparable arrangements" as required by the Schedule. This statement will also acknowledge that, upon request by the self-supplying customer, the public utility transmission provider will share with the customer its reasoning and any related data used to make the determination of whether the customer has made "alternative comparable arrangements."[151] To aid the transmission customer's ability to make an "apples-to-apples" comparison of regulation resources, the Commission will also amend Part 35 of its Regulations by adding a new section (k) to § 37.6,[152] to require each public utility transmission provider to post certain Area Control Error (ACE) data described further below. We find that these reforms are necessary to address the potential for undue discrimination in the provision of Regulation and Frequency Response, including in instances when a customer self-supplies this service using its own resources or purchases from a third-party. Acknowledging the speed and accuracy of the resources used to provide this service will help to ensure that an appropriate quantity of

[151] *See* Appendix B for the revised Schedule 3 of the *pro forma* OATT provisions consistent with this Final Rule.

[152] This regulation will replace the like-numbered proposed regulation related to historical ancillary service requirements data posting from the NOPR that we decline to adopt in section II.A.1.b. of this Final Rule.

resources is utilized for self-supply, whether those resources are faster and more accurate or slower and less accurate than those used by the public utility transmission provider. The weight of comments support reform in this area, including arguments that such a reform will help foster innovation and the entry of newer resources into the market.

112. Under the current *pro forma* OATT, transmission customers considering using their own or third-party resources to self-supply regulation service are required to demonstrate to the public utility transmission provider that they have made "alternative comparable arrangements." However, the *pro forma* OATT provides no further information as to how the determination of "alternative comparable arrangements" would be made. Moreover, the OATT contains no express obligation on the part of the transmission provider to consider the relative speed and accuracy of resources a customer might desire to use in self-supplying Regulation and Frequency Response service. A public utility transmission provider could require a customer seeking to self-supply regulation services to provide a volume of regulation reserves based on the characteristics of the resources used by the public utility transmission provider to provide regulation service, which may not be reflective of the characteristics of the customer's resources. This could under- or overstate regulation reserve requirements depending on the relative characteristics of the resources at issue. It also could impair the customer's ability to self-supply regulation requirements at the lowest possible cost.[153] The Commission finds

[153] For example, a self-supplying customer could save money either by relying on a smaller amount of high quality regulation resources at a slightly higher per-unit price or

(continued…)

that this lack of clarity as to the role of resource speed and accuracy in the determination of "alternative comparable arrangements" for regulation reserve requirements for self-supplying transmission customers must be addressed in order to limit opportunities for potential discrimination in the provision of regulation service by public utility transmission providers.

113. While the Commission initially proposed that each public utility transmission provider should amend its OATT to include a description of how regulation reserve requirement determinations would take into account speed and accuracy of resources, we believe the better course of action at this time is to place the obligation on the public utility transmission provider to take into account speed and accuracy without requiring it to develop detailed tariff language describing the specific process to be used. This will provide the public utility transmission provider with flexibility while also providing the customer with information. While a number of commenters suggested elements for what the public utility transmission provider should be required to provide, the clearest proposal in the comments related to this issue request that public utility transmission providers be required to provide current monthly and 12-month rolling average Control Performance Standard 1 (CPS1), Control Performance Standard 2 (CPS2) and Balancing

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by relying on a larger amount of lower quality regulation resources at a much lower per-unit price. Provided that reliability is maintained, the transmission customer should have the ability to self-supply consistent with its preferences.

Authority ACE Limit (BAAL) scores for Frequency Regulation.[154] However, by itself availability of such information would do nothing to explain how the public utility transmission provider determines regulation reserve amounts. Furthermore, while ACE information might help to characterize the speed and accuracy of the public utility transmission provider's own regulation resources, the Commission believes that using the relatively long duration of monthly and 12-month rolling ACE averages implicit in these scores may not provide information useful for measuring performance over a fraction of an hour, which is the relevant time frame for Regulation and Frequency Response service.

114. Accordingly, the Commission declines to impose a "one size fits all" approach to calculating regulation reserve requirements, consistent with the comments of Hydro Association and California PUC, and declines to require the inclusion of this process in Schedule 3. Rather, we require that Schedule 3 be amended to include a statement that the public utility transmission provider will take into account the speed and accuracy of regulation resources in determining reserve requirements for Regulation and Frequency Response service, including when reviewing whether a self-supplying customer has made "alternative comparable arrangements." Self-supplying customers and their public utility transmission providers will then have a basis to study and negotiate appropriate

[154] CPS1 and CPS2 are described in NERC Reliability Standard BAL-001-0.1a — Real Power Balancing Control Performance. The BAAL criterion is expected to replace CPS2 in that Reliability Standard when it becomes effective, pending final approval by NERC and the Commission.

arrangements case-by-case, very similar to how such interactions take place under other processes such as the interconnection process.

115. That said, we agree with the comments of ESA, Beacon, and California Storage Alliance that transmission customers considering whether or not there would be any economic advantage to self-supply of Regulation and Frequency Response service requirements would need to be able to make an "apples-to-apples" comparison of their resources to those of their public utility transmission provider.[155] Doing so would require the transmission customer to know both the potential avoided cost of purchasing from its public utility transmission provider, and some measure of the speed and accuracy of the public utility transmission provider's Regulation resources. The first requirement is met through the rate filed in the public utility transmission provider's OATT Schedule 3. We believe the second requirement can only be met through a new OASIS posting requirement.

116. As noted earlier, the public utility transmission provider's CPS1, CPS2, and BAAL scores might address this need in concept, except that they currently reflect long-term averages that do not match the relevant time frame for Regulation and Frequency Response service. We believe the one-minute and ten-minute average ACE data collected by public utility transmission providers to produce the CPS1, CPS2, and BAAL scores would be more useful for this purpose because it does match the relevant time

[155] ESA Comments at 8-10; Beacon Comments at 7-9; and California Storage Alliance Comments at 5-6.

frame. Accordingly, in order to ensure a level of transparency adequate to support self-supply decision-making by transmission customers, we will require public utility transmission providers to post historical one-minute and ten-minute ACE data on OASIS. For this purpose, we find that historical data for the most recent calendar year, updated once per year, should meet the need. This information is already collected and provided to NERC, through balancing area operators and reliability coordinators, so there should be minimal incremental burden associated with posting it on OASIS.

117. The Commission's standard filing requirements, including opportunity for intervention and comment, address Morgan Stanley's request to establish a process for market participants to challenge and resolve speed and accuracy assumptions. For example, as is the case in interconnection agreement proceedings, the transmission service agreement that reflects an individually negotiated self-supply arrangement for Regulation and Frequency Response service can be filed by the public utility transmission provider unexecuted. This will leave the transmission customer free to protest relevant aspects of the public utility transmission provider's determination of whether the customer has made "alternative comparable arrangements," including as those arrangements relate to the speed and accuracy of the customer's proposed Regulation resources.

118. With respect to Morgan Stanley's request that public utilities demonstrate equivalent treatment for their own or their affiliate's regulation requirements, we find that the increased transparency required by this Final Rule will accomplish this goal. The requirements adopted above apply to the public utility transmission provider's own

regulation resources, in the sense that it must apply the same procedures for determining regulation reserve requirements to itself as it does to self-supplying customers.

119. With respect to the request of TAPS that the Commission state explicitly that the NOPR's proposal to account for the speed and accuracy of customer self-supplied regulating resources includes demand resources, we note that OATT Schedule 3, as amended by Order No. 890 makes clear that Regulation and Frequency Response service may be provided from non-generation resources capable of providing the service. Accordingly, a transmission provider's determination of regulation reserve requirements should take into account the speed and accuracy characteristics of the resources in question, whether they are generation-based or otherwise.

120. Turning to the various requests that the Commission step beyond the NOPR proposals, the Commission declines to require two-part pricing for regulation capacity and performance set forth in Order No. 755. We conclude that the requirements adopted above will allow customers and the Commission to ensure that the speed and accuracy of resources used for regulation reserves are properly taken into account in reserve level determinations within the context of the bilateral markets within which non-RTO/ISO public utility transmission providers operate. The Commission also declines commenter requests to provide incentive rate treatment for purchases of Regulation and Frequency Response service by public utility transmission providers to meet their OATT requirements. Commenters are not clear as to what mechanism they believe the Commission should use to require such treatment, and the Commission sees no reason to implement an incentives program in the context of ancillary services rate design.

121. With respect to EEI's comments regarding differences between primary frequency response and secondary frequency regulation, the Commission acknowledges these distinctions. Improving the transparency regarding the resources used to provide Regulation and Frequency Response service under OATT Schedule 3 does not alter the ability of any balancing authority to maintain adequate reserves to meet reliability requirements. The Commission thus sees no need to wait for the industry to better understand the relationship and interdependencies between primary and secondary frequency response prior to adopting the requirements of this final rule. The Commission will evaluate a public utility transmission provider's compliance proposal as part of the case-by-case review discussed above, which will provide the public utility transmission provider the opportunity to demonstrate how it establishes its regulation reserve requirements.

C. Accounting and Reporting for Energy Storage Operations

122. In the NOPR, the Commission proposed to revise certain accounting and reporting requirements under its USofA and its forms, statements, and reports contained in Form Nos. 1, 1-F, and 3-Q. The Commission stated that the revisions were needed so that entities subject to the Commission's accounting and reporting requirements could better account for and report transactions associated with energy storage devices used in public utility operations. Moreover, the Commission noted that this information is important in developing and monitoring rates, making policy decisions, compliance and enforcement initiatives, and informing the Commission and the public about the activities of entities subject to the accounting and reporting requirements.

123. The Commission proposed that new electric plant and associated O&M expense accounts be created to provide for the recording of investment and O&M costs of energy storage assets. The Commission also proposed to create a new purchased power account to provide for recording the cost of power purchased for use in storage operations. In addition, the Commission proposed that new Form Nos. 1 and 1-F schedules be created and existing schedules in the forms and Form No. 3-Q be amended to report operational and statistical data on storage assets. Finally, the Commission inquired about whether entities seeking to recover costs of energy storage assets and operations simultaneously under cost-based and market-based rates should be required to forego previously granted accounting and reporting waivers associated with market-based rates, and if so, should the requirement to forego the waivers be subject to some percentage threshold based on a ratio of cost-based cost recovery to total cost to be recovered.

124. While most commenters support the Commission's proposal to revise the accounting and reporting requirements, there were several recommendations to make adjustments to the proposals and also requests for clarification of certain proposals. Only Solar Energy Association opposed the proposal, stating, without elaboration, that it believes it is premature to establish reporting requirements for energy storage.[156] In the NOPR, the Commission responded to similar arguments regarding maturity of the energy storage industry as it relates to the use of energy storage assets to provide public utility

[156] Solar Energy Association Comments at 7.

services, and found those arguments unconvincing.[157] The Commission explained that there is a need for certainty in the accounting and reporting treatment for energy storage assets and operations, especially in instances where utilities seek to recover costs of energy storage operations in cost-based rates. Solar Energy Association has not provided new information that we could consider on this issue, therefore we find Solar Energy Association's argument unconvincing.

1. Electric Plant Accounts

Commission Proposal

125. In the NOPR, the Commission stated that the existing primary plant accounts do not explicitly provide for recording the cost of energy storage assets. The Commission concluded that this could lead to inconsistent accounting and reporting for these assets by utilities subject to the accounting and reporting requirements, making it difficult for the Commission and others to determine costs related to energy storage assets for cost-of-service rate purposes. The Commission also noted that the lack of transparency affects interested parties,' including the Commission's, ability to monitor these utilities' operations to prevent and discourage cross-subsidization between cost-based and market-based activities. To address these issues, the Commission proposed to create electric

[157] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 71.

plant accounts in the existing functional classifications – production, transmission, and distribution – for new energy storage assets.[158]

126. The Commission proposed that the installed costs of energy storage assets be recorded in the accounts based on the function or purpose the asset serves. On this basis, an asset that performs a single function will have its cost recorded in a single plant account. In instances where an energy storage asset is used to perform more than one function or purpose, the Commission proposed that the cost of the asset be allocated among the relevant energy storage plant accounts based on the functions performed by the asset and the allocation of the asset's costs through cost-based rates that are approved by a relevant regulatory agency, whether federal or state.[159]

Comments

127. In general, the commenters applaud the Commission's efforts to improve transparency and prevent double-recovery of energy storage-related costs. The proposal to require utilities to record the costs of single-function energy storage assets in a single plant account garnered widespread support. However, the proposal to require utilities to allocate the costs of multi-function energy storage assets to the relevant energy storage plant accounts based on the functions performed and approved rate recovery, received

[158] Account 348, Energy Storage Equipment-Production; Account 351, Energy Storage Equipment-Transmission; and Account 363, Energy Storage Equipment-Distribution, respectively.

[159] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 81.

comments supporting and opposing the proposal. Commenters that agree with the proposal generally indicate that the accounting would provide necessary transparency of a utility's operations,[160] while commenters that oppose the proposal generally indicate that the accounting would place an undue administrative burden on utilities and is inconsistent with the Commission's existing accounting rules.[161]

128. Public Interest Organizations state that they support the development of requirements that can reveal the activities and costs of energy storage operations thorough greater transparency and detail. California PUC similarly states that in the event an energy storage developer intends to use a facility to perform multiple functions, the proposed accounting and reporting should provide transparency. NU Companies state that they support flexible rate treatment for energy storage assets and believe the proposed accounting will provide transparency required to guard against inappropriate cross subsidization of various services and double recovery cost.

129. In opposition to the proposal, SDG&E contends that while it generally agrees with the Commission's allocation "concept" to account for energy storage assets by functional category, i.e., production, transmission, and distribution, it is concerned that generally applicable financial tools may not be able to efficiently track or monitor up to three

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[160] Public Interest Organizations Comments at 9-10; California PUC Comments at 9; NU Companies Comments at 4; APPA Comments at 5; ESA Comments at 18-19; TAPS Comments at 28-29; and California Storage Association Comments at 11-12.

[161] Southern California Edison Comments at 8; SDG&E Comments at 2-3; and EEI Comments at 29-30.

functional categories for one asset without increased and ongoing manual intervention.[162] SDG&E argues that it agrees that the initial allocation concept would capture expenses by each function as the Commission intends; however, if the utility subsequently changes its initial allocation in the future the proposed accounting would create an unnecessary administrative burden that if a mistake is made could result in costs of the asset being stranded. SDG&E contends that to ensure the asset is accounted for properly so that asset costs are not stranded, a utility would be required to continuously monitor the asset to make sure its initial allocation is consistent with the asset's actual usage. SDG&E acknowledges that the NOPR addresses this concern;[163] however, SDG&E asserts that there is a more straightforward approach that can be used to allocate the costs of a multi-function energy storage asset. SDG&E advocates, instead of using multiple plant accounts, that the cost of an energy storage asset be recorded in a single plant account and its cost allocated to the various functions it performs using current ratemaking methods.

130. Similar to SDG&E, Southern California Edison and EEI also complain of an increased administrative burden resulting from allocating an energy storage asset's cost across multiple plant accounts as proposed in the NOPR. Southern California Edison and

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[162] SDG&E Comments at 2-3.

[163] SDG&E cites to the NOPR proposal that a utility transfer reallocated cost of an energy storage asset in accordance with the instructions of Electric Plant Instruction No. 12, Transfers of Property, 18 CFR Part 101 (2012). *See* SDG&E Comments at 3-4 (citing to NOPR, FERC Stats. & Regs. ¶ 32,690 at P 82).

EEI contend that it would be necessary to create multiple unique property records for an energy storage asset to allocate its costs across multiple functions. Southern California Edison and EEI argue that having multiple records for each asset would require significant manual intervention while providing little practical value.[164] Additionally, Southern California Edison and EEI assert, without providing any detail, that the NOPR proposal is inconsistent with the general principle that each asset should have a single record within an accounting system.[165] Southern California Edison and EEI contend that there is neither a precedent for creating multiple property records for a single asset, nor a precedent for creating a record for a partial asset. Further, EEI argues that to the extent the different functions the cost of an energy storage asset could be spread across are subject to different depreciation rates, a single asset with a unique, individual economic life would be depreciated over multiple periods.

131. EEI indicates that while it generally opposes the NOPR's proposed accounting, it believes that in some circumstances the proposal may be a practical alternative for companies desiring to use it.[166] Therefore, EEI advocates that utilities be afforded two options to account for energy storage assets that are used to perform multiple functions.

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[164] Southern California Edison Comments at 8; and EEI Comments at 30.

[165] Southern California Edison Comments at 8 and n 8 citing Definition No. 8 Paragraph (A)(5), Continuing Plant Inventory Record, 18 CFR Part 101 (2012); and EEI Comments at 30.

[166] EEI Comments at 29-31.

EEI proposes that utilities be allowed to either: (1) record the costs of multi-function storage asset costs as proposed in the NOPR or (2) record the costs of the assets in a single plant account based on the primary function of the asset and to allocate costs to specific functions performed through the ratemaking process. Moreover, EEI recommends that the Form Nos. 1, 1-F, and 3-Q be amended to provide for reporting the option each company uses. EEI contends that allowing both options will afford companies the ability to maintain accounting and reporting records in the most efficient manner while providing transparency via reporting and uniformity in the ratemaking process.

132. Southern California Edison supports EEI's option (2). Southern California Edison and EEI contend that the option (2) approach is consistent with the approach used for certain assets that provide both state-jurisdictional and FERC-jurisdictional functions.[167] Southern California Edison and EEI explain that the ratemaking process may include a formula or special study in order to appropriately allocate the costs across functions.

Commission Determination

133. SDG&E's, Southern California Edison's, and EEI's arguments that requiring utilities to allocate the costs of energy storage assets that perform multiple functions across the relevant energy storage plant accounts places an undue administrative burden on utilities are unpersuasive. These commenters generally argue that this perceived

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[167] Southern California Edison Comments at 8; and EEI Comments at 31-32.

undue administrative burden results from a requirement that utilities maintain records that track the usage of energy storage assets and costs associated with such use. However, utilities would be required to maintain records with this information whether accounting for the costs of an asset in multiple accounts as proposed in the NOPR or accounting for the costs in a single account as proposed by SDG&E, Southern California Edison and EEI. For example, information on the allocation of the cost of an energy storage asset to a particular function will have to be maintained by utilities operating multi-function, multi-cost recovery energy storage assets, regardless of whether the information is required to be reported in the reporting forms as proposed in the NOPR or if the information is not reported in the forms yet is used in ratemaking determinations as proposed by SDG&E, EEI, and Southern California Edison. Because utilities with energy storage operations that recover any portion of costs on a cost-of-service basis will be required to maintain use and cost allocation information on the assets, requiring these utilities to implement the NOPR's accounting proposal does not result in an additional burden on utilities that could be considered unduly burdensome.

134. Moreover, SDG&E's argument that costs could possibly be stranded if a utility does not appropriately account for energy storage operations is also unconvincing. This possibility exists throughout the utility industry and is not uniquely attributable to utilities with energy storage operations. Administrative errors, such as errors in accounting, that lead to costs being stranded due to inadequate or insufficient internal controls over policies, practices, and procedures used to track costs associated with assets represent a risk for all utilities whether or not the utilities own energy storage assets.

Risks of this nature are inherent to all utilities' operations. Utilities must maintain adequate, sufficient, and reliable internal controls to reduce the probability of this risk affecting operations.

135. As support for their argument that the NOPR's proposed accounting causes an undue administrative burden and that their advocated accounting avoids the burden, Southern California Edison and EEI contend that their proposal to record the costs of an energy storage asset in a single plant account could require utilities to implement a formula or special study to appropriately allocate the costs of the asset across multiple functions. However, this contention does not support their argument. A formula or special study would require utilities to maintain the same information on the functions performed by an energy storage asset and costs associated with such performance, as would be required by the NOPR's proposed accounting. Thus, a formula or special study would not avoid the administrative burden associated with accounting for energy storage assets and operations. Furthermore, Southern California Edison and EEI have not provided information to support a determination that the burden would be decreased by implementing their proposed accounting. Their proposal would result in less transparent reporting of information on energy storage operations as compared to the NOPR's proposed accounting.

136. While the commenters argue that the accounting proposal might require increased manual intervention to account for and report storage assets, it is not clear that such intervention, if any, results in an undue administrative burden. As the Commission observed in the NOPR, uniform, transparent, and consistent reporting of information on

energy storage operations by utilities is essential, especially by those seeking to recover costs of energy storage services in cost-based rates.[168] We believe that adopting the NOPR's proposed accounting and reporting revisions will improve transparency.[169] The revisions will enhance the Commission's and other form users' ability to make a meaningful assessment of a utility's cost-of-service rates, and will provide for better monitoring for cross-subsidization. In instances where an energy storage asset performs multiple functions, it is imperative that costs associated with each function be transparent and allocable to the function performed so that cross-subsidization of costs can be prevented. SDG&E, EEI, and Southern California Edison have not provided information that would refute the Commission's determination in the NOPR that the accounting proposal is not overly burdensome.

137. EEI's recommendation that utilities be afforded two options to account for and report storage assets that provide multiple services and recover associated costs simultaneously under cost-based and market-based rate methods is not consistent with the intent of the NOPR's proposed accounting and reporting revisions. The NOPR proposed one method to account for energy storage assets performing multiple functions under multiple cost recovery mechanisms to ensure that utilities account for the assets on a uniform and consistent basis. EEI's proposal for two methods of accounting could result

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[168] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 71.

[169] *Id*. P 72.

in similarly-situated utilities with energy storage assets reporting the same type of transaction differently. This would not provide the uniformity sought by the accounting and reporting proposals and could disrupt consistency, which would make it difficult to compare utilities with energy storage operations across the industry. In addition, adopting EEI's proposal to record the costs of the assets in a single account would reduce the transparency of information reported in the forms. This information is critical to the clarity and transparency needed to support a reasonable analysis of a utility's cost. Consequently, we will not adopt EEI's proposal.

138. Southern California Edison's assertion that the NOPR requirement adopted here is not consistent with Definition No. 8, Continuing Plant Inventory Record, is incorrect.[170] While the definition pre-dates the NOPR's accounting and reporting requirements, the definition is broad enough such that its premise is as relevant for energy storage assets as it is for conventional electric plant assets. The accounting and reporting proposals require utilities to maintain a detailed record of the descriptive operational and cost information associated with energy storage assets consistent with the provisions of Definition No. 8.

139. Further, Southern California Edison's and EEI's contentions that there is no precedent for creating multiple property records for a single or partial asset misconstrues the proposed accounting and reporting requirements. The accounting and reporting

[170] 18 CFR Part 101 (2012).

proposals we adopt here do not require utilities to maintain multiple records for a single or partial asset as Southern California Edison and EEI contend. Rather, the reforms maintain the existing requirement of Definition No. 8 that utilities maintain descriptive operational and cost information on each asset. Moreover, we do not consider allocating the cost of a single asset to multiple property accounts to be the same as creating multiple property records as though there were multiple assets. A utility can maintain information on a single energy storage asset with costs allocated to multiple plant accounts in a single record that provides descriptive operational and cost information on the asset. Additionally, in accordance with General Instruction No. 12, Records for Each Plant, utilities are required to maintain a record, by electric plant accounts, on the book costs of each plant owned.[171] The requirement to record the cost of a multi-function, multi-cost recovery energy storage asset to more than one plant account is consistent with this instruction.

140. EEI argues that if different depreciation rates are applied to a single energy storage asset in accordance with each function the asset performs the various allocated costs of the asset would be depreciated over multiple periods. EEI is correct that there is a possibility of this occurring if costs of a single asset were subjected to multiple differing depreciation rates. However, this has neither been the experience of this Commission nor

[171] The instructions indicate that the term "plant" means each generating station and each transmission line or appropriate group of transmission lines. This term is also applicable to energy storage facilities. 18 CFR Part 101 (2012).

do we expect that a utility's primary rate regulator would subject a single asset to multiple depreciation rates. Although the costs of an energy storage asset may be allocated across multiple plant accounts, we agree with EEI that the asset is a single unique asset with a single economic life. Thus, there should be a single depreciation rate applied to the asset that allocates in a systematic and rational manner the service value of the asset over its service life. To the extent possible, a utility should apply a single depreciation rate to an energy storage asset.

141. The reforms adopted here are designed to provide needed transparency, but also to reflect a fair balance between the need for information and the additional burden on the utility. We believe these accounting reforms for energy storage reflect this balance. Accordingly, Account 348, Energy Storage Equipment-Production, Account 351, Energy Storage Equipment-Transmission, and Account 363, Energy Storage Equipment-Distribution, as proposed in the NOPR are adopted in this Final Rule.

2. Power Purchased Account

Commission Proposal

142. In the NOPR, the Commission noted that to provide some electrical services, energy storage devices may need to maintain a particular state of charge, or as in the case of compressed air facilities, may need to maintain some minimum pressure, and that some companies may be required to purchase power to maintain a desired state of charge or pressure. Further, the Commission determined that the benefits of enhanced transparency, in this instance, resulting from having the cost of power purchased for energy storage operations reported separately from other power purchases, outweighs the

associated burden of requiring the accounting. Therefore, the Commission proposed a new Account 555.1, Power Purchased for Storage Operations, to report the cost of: (1) power purchased and stored for resale; (2) power purchased that will not be resold but instead consumed in operations during the provisioning of services; (3) power purchased to sustain a state of charge; and (4) power purchased to initially attain a state of charge, with item 4 being capitalized as a component cost of initially constructing the asset.

Comments

143. Most commenters support the proposed accounting. For example, ESA and others state that the new account will enhance the transparency of reporting the operations of storage resources.[172] Hydro Association indicates that similar accounting should be established for the cost of power purchased for pumped storage operations to account for initial unit testing and commissioning.[173]

144. Hydro Association states, in particular, for closed-loop pumped storage projects, the first unit testing entails pumping or charging the upper reservoir. Hydro Association explains that at an early stage of development of a pumped storage project, the generating station is months away from being declared "commercial" and testing the station requires energy from the grid to initially attain a fully charged state (i.e., a full upper reservoir). Hydro Association argues that these initial charging costs should be capitalized. Further,

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[172] ESA Comments at 21-22.

[173] Hydro Association Comments at 12-13.

Hydro Association contends that costs incurred to test the generating station should likewise be capitalized into the cost of the project. In contrast to Hydro Association's assertion that the existing accounting requirements for pumped storage operations are not sufficient, EEI argues that the existing requirements appropriately and transparently provide for pumped storage plants.[174]

Commission Determination

145. We will adopt the new Account 555.1, Power Purchased for Storage Operations, as proposed in the NOPR. The accounting reforms here requiring initial charging and testing costs to be capitalized seek to apply existing requirements for conventional electric plant, such as pumped storage plant, to new energy storage assets. The requirements do not seek to differentiate the accounting for new energy storage assets from pumped storage plant in this instance.

146. We disagree with Hydro Association's assertion that the existing accounting requirements for pumped storage operations are not sufficient. Contrary to Hydro Association's assertion, pumped storage is not prohibited, for accounting purposes, by the existing accounting rules and regulations from capitalizing costs incurred to initially bring a pumped storage facility into operation nor is it prohibited from capitalizing costs incurred to test pump storage facilities prior to commercial operation. Electric Plant Instruction No. 3, Components of Construction Cost, provides that expenses incidental to

[174] EEI Comments at 27.

the construction of plant such as cost to initially attain a fully charged state to bring the plant into operation may be capitalized as a component cost of the plant.[175] Further, Electric Plant Instruction No. 9, Equipment, provides that the costs of plant shall include necessary costs of testing or running plant or parts thereof during the test period prior to the plant becoming ready for or being placed in service.[176] Consequently, we agree with EEI's statement that the existing accounting requirements for pumped storage are sufficient. The NOPR proposals for Account 555.1 are adopted in this Final Rule as proposed.

3. Operation and Maintenance Expense Accounts

Commission Proposal

147. In the NOPR, the Commission observed that there are O&M expenses related to the use of energy storage assets to provide utility services, and there are no existing O&M expense accounts in the USofA specifically dedicated to accounting for the cost of energy storage operations. Therefore, the Commission proposed new O&M expense accounts for energy storage-related O&M expenses that are not specifically provided for in the existing O&M expense accounts in the USofA and revision of certain existing O&M expense accounts. Specifically, the Commission proposed that energy storage expenses be recorded in Account 548.1, Operation of Energy Storage Equipment, and Account

[175] 18 CFR Part 101 (2012).

[176] *Id.*

553.1, Maintenance of Energy Storage Equipment, for energy storage plant classified as production; Account 562.1, Operation of Energy Storage Equipment, and Account 570.1, Maintenance of Energy Storage Equipment, for energy storage plant classified as transmission; and Account 582.1, Operation of Energy Storage Equipment, and Account 592.2, Maintenance of Energy Storage Equipment, for energy storage plant classified as distribution, to the extent that the existing O&M expense accounts do not adequately support recording of the cost.[177]

Comments

148. The commenters support the proposed O&M expense accounts. Most commenters state that the proposed accounts will provide sufficient transparency of energy storage-specific O&M expenses.[178]

Commission Determination

149. This Final Rule adopts the NOPR proposals for the O&M expense accounts with the exception that the account number for Account 582.1 will be changed to Account 584.1. The name and text of the account will remain as proposed in the NOPR.

150. In addition, the NOPR proposed that the text of Account 592, Maintenance of Station Equipment (Major only), and Account 592.1, Maintenance of Structures and Equipment (Nonmajor only), be revised such that the accounts do not provide for O&M

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[177] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 96.

[178] *See, e.g.*, ESA Comments at 22; Beacon Power Comments at 21-22; and California Storage Alliance Comments at 17.

expenses related to energy storage operations and also to remove the reference to Account 363. Accordingly, the following text is struck from Accounts 592 and 592.1:

"and account 363, Storage Battery Equipment."

4. New and Amended Form Nos. 1, 1-F, and 3-Q Schedules

Commission Proposal

151. In the NOPR, the Commission acknowledged that the existing schedules in the Form Nos. 1, 1-F, and 3-Q do not provide for reporting information on new types of energy storage assets such as batteries and flywheels.[179] Consequently, the Commission proposed to amend several schedules of the Form Nos. 1, 1-F, and 3-Q to include energy storage plant, purchased power, and O&M expense accounts.[180] In addition, the Commission proposed to add new schedule pages 414-416, Energy Storage Operations (Large Plants), and pages 419-420, Energy Storage Operations (Small Plants), to the Form Nos. 1 and 1-F to provide for reporting operational and statistical information on new types of energy storage assets.[181] The Commission proposed that filers with energy storage assets having a rated capacity of 10,000 kilowatts (KW) or more record the

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[179] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 101.

[180] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 106; and Appendix B Proposed Amendments to Form Nos. 1, 1-F and 3-Q.

[181] The text of the NOPR indicated that the schedules pages were 414-417 and 419-421 for the respective Large and Small Plant schedules. However, the proposed schedules included in Appendix B of the NOPR used different page numbers. We clarify that the schedule page numbers are 414-416 and 419-420, for the respective Large and Small Plant schedules, as indicated in this Final Rule.

operations of the assets on schedule pages 414-416, and filers with energy storage assets with less than 10,000 KW of capacity record the operations on schedule pages 419-420. In addition, the Commission sought comment on whether 10,000 KW is an appropriate threshold for requiring utilities to report more detailed plant and cost information for energy storage plant.[182] The Commission noted that certain existing schedules in the Form No. 1 have a 10,000 KW threshold.[183] However, the Commission opined that this threshold may not be appropriate for new energy storage assets that in many instances may be rated below 10,000 KW.

Comments

152. Most commenters support the NOPR's forms proposals, and a few commenters recommend revisions to the forms in addition to those proposed.[184] Consistent with its recommendation that the Commission implement two options to account for energy storage assets, EEI proposes that the forms provide for disclosing the specific option a

[182] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 103.

[183] *See* Form No. 1, schedule pages 408-409, Generating Plant Statistics (Large Plants) and schedule pages 410-411, Generating Plant Statistics (Small Plants). Schedule pages 408-409 require filers to report more detailed information for generating assets with a rated capacity of 10,000 KW or more than schedule pages 410-411, which require less detailed information for generating assets with a rated capacity of less than 10,000 KW.

[184] *See, e.g.*, APPA Comments at 5; Beacon Comments at 22-23; California Storage Alliance Comments at 19; and ESA Comments at 23.

utility is using to account for the assets.[185] However, because we are not adopting EEI's recommendation for two accounting options, its disclosure proposal is unnecessary as utilities will have one uniform method for accounting for energy storage assets.

153. Hydro Association contends that there are shortcomings in the way the Form No. 1 treats existing pumped storage plants, as they are now used, and it suggests modifications that it believes will improve reporting of information on the assets. Hydro Association recommends that the heading of Line 6 "Plant Hours Connect to Load While Generating" of schedule pages 408-409, Pumped Storage Generating Plant Statistics (Large Plants), in the Form No. 1 be changed to read "Plant Hours Connect to Load."[186] Hydro Association reasons that the total hours a facility is synchronized and connected to the grid are important to identify. Hydro Association explains that a facility's effectiveness is based on its total utilization factor, which Hydro Association describes as the sum of hours generating, pumping, and condensing. Hydro Association asserts that this sum should be reported on Line 6 under its proposed heading. Alternatively, Hydro Association proffers that if further detail is needed, the heading of Line 6 can remain as is and two new line items can be added to the schedule to report pumping and condensing hours.

154. Further, Hydro Association also contends that Line 38, "Expenses for KWh (line 37/9)" incorrectly calculates the cost per kilowatt hour (KWh) of pumped storage

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[185] EEI Comments at 5.

[186] Hydro Association Comments at 11.

operations.[187] Hydro Association asserts that the calculation should include energy generated and energy used for pumping operations. Hydro Association proposes that Line 38 be revised to read as "Expenses for KWh (line 37/9+10)."

155. TAPS recommends revisions to new schedule pages 414-416, Energy Storage Operations (Large Plants).[188] TAPS observes that the instruction for column heading (l) refers to "revenues from energy storage operations" while the name of the column is "Revenues from the Sale of Stored Energy." TAPS asserts that because revenues from energy storage operations can be garnered by means other than from energy sales, the name of the column should be revised to be consistent with the instructions of the column or additional columns should be created, with corresponding instructions, to report other types of revenues.

156. In regard to the 10,000 KW threshold, California Storage Alliance states that it believes 10,000 KW is an appropriate threshold for requiring a difference in the reporting requirements for the assets.[189] In contrast, Beacon and ESA recommend a higher threshold of 20,000 KW.[190] Beacon and ESA assert that this threshold would align with the Small Generator Interconnection threshold and the capacity value for many existing and planned energy storage assets.

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[187] *Id*.

[188] TAPS Comments at 28-29.

[189] California Storage Alliance Comments at 19.

[190] Beacon Comments at 22; and ESA Comments at 22-23.

Commission Determination

157. We generally agree with the premise of Hydro Association's contention that Line 6 of schedule pages 408-409 could benefit from additional detail. However, the cost of additional detail must be weighed against any associated benefit that could result. To this end, we strive to achieve a balance such that the cost of implementing new reporting requirements does not excessively exceed the benefits of implementation. A particularly important benefit to the Commission of additional detail is that it provides data necessary for the regulation and review of companies' operations. Hydro Association has neither explained how information on pumping and condensing hours is needed for the regulation and review of pumped storage operations nor has it explained how the information would be beneficial for other uses. Hydro Association indicates that this information will provide for a measure of a facility's effectiveness, however, it is not clear that the cost of requiring this information is on par with any perceived benefits or that the requirement would not be overly burdensome. Consequently, we will not adopt Hydro Association's proposal to include the sum of generating, condensing and pumping on Line 6, nor will we adopt its alternate proposal to add two new line items to the schedule.

158. With regard to Hydro Association's contention that Line 38 of schedule pages 408-409 incorrectly calculates the cost per KWh of pumped storage operations, this line is not intended to report this cost, rather it is intended to report the cost per KWh of energy generated and transmitted to the grid. Line 38 of the schedule includes a formula that requires filers to divide total production expenses reported on Line 37 by energy

generated and transmitted to the grid reported on Line 9. Nevertheless, we recognize Hydro Association's underlying concern that, as a conforming change given the other accounting requirements in this Final Rule, the schedule should report this information, including the energy generated and energy used in pumping, as illustrated in the formula example submitted by Hydro Association – Line 37/9+10.

159. We agree that reporting this information on schedule pages 408-409 will help create a more accurate database for benchmarking and O&M cost studies, and this information also will assist interested parties', including the Commission's, review of the operations of pumped storage facilities across the industry. We note that the data inputs needed to perform the calculation are currently required to be reported on Lines 9, 10 and 37 of schedule pages 408-409, so this requirement is not wholly new and the burden on utilities to calculate and report the information specifically on schedule pages 408-409 is minimal. Accordingly, the item on Line 38 of schedule pages 408-409 is revised to read "Expenses per KWh of Generation (line 37/line 9)" and a new Line 39 is added which reads "Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))."

160. TAPS asserts that revenues from energy storage operations can originate from activities other than energy sales, thus it recommends that proposed schedule pages 414-416 be revised to provide for other types of revenues. We agree that there are potentially other activities that energy storage operators can engage in to generate revenue. For example, as TAPS noted, an energy storage operator can conceivably earn revenues from the sale of storage capacity. While we are not aware of any instances where these types of storage capacity transactions have occurred, to ensure that the schedule provides

adequate flexibility to allow for the reporting of all revenues from energy storage operations we will revise the name of the column to read "Revenues from Energy Storage Operations." We will not create additional columns to report the various types of revenue because the instructions to the schedule already require filers to disclose this information in a footnote.

161. Beacon and ESA recommend that the Commission align the threshold for detailed reporting in the new schedules with the existing 20,000 KW threshold established in Order No. 2006 for the interconnection of small generators.[191] To this end, Beacon and ESA propose a 20,000 KW threshold as opposed to the 10,000 KW proposed in the NOPR. However, the 20,000 KW threshold in Order No. 2006 was established notwithstanding the requirement that small generators having 10,000 KW or more but less than 20,000 KW that are subjected to the Commission's accounting and reporting requirements would be subjected to a higher reporting burden than companies with generators of less than 10,000 KW. In this instance, the Commission determined that while there is a need to further remove barriers to participation in energy markets by establishing terms and conditions under which public utilities must provide interconnection service, there is also a parallel need for detailed information on the

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[191] *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180, *order on reh 'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), *order on clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006). This order originally set forth the terms and conditions under which public utilities must provide interconnection service to Small Generating Facilities of no more than 20,000 KW.

activities and operations of companies using these assets in the provisioning of utility services. Thus, the Commission maintained its existing 10,000 KW threshold for these small generators.

162. Beacon and ESA have not provided information that supports a decreased reporting burden for energy storage assets over 10,000 KW as compared to the reporting burden of conventional assets that are currently subject to the 10,000 KW threshold. Nor has Beacon or ESA provided information that would support increasing the existing 10,000 KW threshold for conventional assets to maintain parity between those assets and energy storage assets. Their proposal may result in an unduly discriminatory reporting requirement for energy storage assets compared to conventional assets, therefore we will not adopt the recommended 20,000 KW reporting threshold.

163. We will adopt the NOPR's proposed 10,000 KW threshold as this amount is neither unduly conservative nor is it overly burdensome. As we indicated in the NOPR, information that would be reported for energy storage assets and operations differs little from other data public utilities maintain under the USofA.[192] If a utility owns and operates these energy storage assets, reporting information on them in the proposed accounts and FERC form schedules should not be burdensome.

[192] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 73.

164. Finally, we will amend schedule pages 2-4, 204-207, 320-323, 324a-324b, 326-327, 397, and 401a of the Form Nos. 1, 1-F, and 3-Q as proposed in the NOPR.[193] We note that these amendments include revising schedule page 401a, Electric Energy Account, of the Form No. 1 to change the title of line item 10 to "Purchases (other than for Energy Storage)" and add a new line item 11 "Purchases for Energy Storage" to provide for reporting power purchased for energy storage operations. These changes require an additional line item on Form No. 1 schedule page 401a to provide for reporting stored energy because total net sources of energy must equal total disposition of energy as instructed by the requirement on Line 30 of the schedule. Utilities with energy storage operations that have stored energy as of the reporting date of the form must report the amount by megawatt hour in the schedule so that total net sources of energy is equal to total disposition of energy reported. Accordingly, as a conforming change, a new line item titled "Total Energy Stored" will be added to schedule page 401a under the heading "Disposition of Energy."

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[193] NOPR, FERC Stats. & Regs. ¶ 32,690 at Appendix B Proposed Amendments to Form Nos. 1, 1-F, and 3-Q.

5. Other Accounting and Reporting Issues

a. Existing Waivers of Accounting and Reporting Requirements

Commission Proposal

165. In the NOPR, the Commission proposed that public utilities currently providing jurisdictional services and recovering costs of the services under market-based rates that have been granted waiver of the accounting and reporting requirements and that seek recovery of a portion of service costs under cost-based rates, be required to forego the previously issued waivers and account for and report all cost and operational information to the Commission in accordance with its accounting and reporting requirements.[194] In addition, the Commission also inquired whether there should be a percentage of cost recovery threshold or other determining factor that triggers the accounting and reporting obligations in this situation, or should any instance of multiple cost recovery, regardless of the percentage of a utility's total costs, trigger the accounting and reporting obligations.

Comments

166. Most commenters agree with the proposal to rescind previously issued waivers and many of these commenters argue that there should not be a percentage threshold that triggers the requirement. California Storage Alliance states that rescinding the waivers will enhance transparency and facilitate development and monitoring of the cost-based

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[194] *Id*. P 75.

portion of rates.[195] Further, California Storage Alliance states that there should not be a percentage threshold that triggers accounting and reporting requirements. California Storage Alliance, and others,[196] also recommend that in instances where a competitive solicitation process is used to determine recovery of the cost-based portion of rates, a public utility should not be required to forego any reporting and accounting waivers. In further describing their position, these commenters suggest that a particular "storage asset may be capable of simultaneously providing two distinct functions, one traditionally cost-based use, and another generally market-based." They then posit the possibility of a public utility issuing a competitive solicitation solely for the "cost-based use." Their comments then assert that the winning bidder would be obligated to provide the "cost-based service" and would be paid through a "rate-based mechanism."[197] We also received requests to clarify that the waivers will only be rescinded if energy storage is involved.[198]

<u>Commission Determination</u>

167. We will adopt the NOPR proposal requiring public utilities to forego previously issued accounting and reporting waivers in instances where the utility seeks to recover

[195] California Storage Alliance Comments at 10.

[196] California Storage Alliance Comments at 10-11; ESA Comments at 18; and Beacon Comments at 18.

[197] *Id.*

[198] Indicated Suppliers Comments at 6 -11; EPSA Comments at 13; and EEI Comments at 33-34.

costs associated with operation of an energy storage asset simultaneously under market-based and cost-based rate recovery mechanisms. We will not impose a percentage recovery threshold, therefore any cost-based recovery of the cost will trigger rescission of previously granted accounting and reporting waivers.

168. Regarding the comments of California Storage Alliance, ESA, and Beacon, the Commission clarifies that sellers under a competitive solicitation that meets the requirements of this Final Rule[199] will not be required to forego any prior accounting and reporting waivers. However, we feel it necessary to explain that the reason for this outcome differs from what these commenters seem to propose.

169. Their comments seem to indicate a belief that there are some products that are inherently cost-based and others that are inherently market-based, and that if a competitive solicitation were held for a cost-based product, the resulting rates would still be cost-based. We are not persuaded by these commenters' arguments that products should be classified as inherently cost-based or market-based. Some potential sellers of these products will qualify to sell them at market-based rates because they either lack market power in the relevant product market, or it has been adequately mitigated. Other sellers who do not qualify to make market-based sales, because they either have market power or cannot prove they lack it, will be limited to charging cost-based rates.

[199] *See supra* PP 87-90.

170. Under the competitive solicitation proposal at bar, proof that the competitive solicitation meets the requirements of this Final Rule will demonstrate that a seller qualifies to make market-based sales at the rates resulting from the solicitation, and thus can avoid having to justify those rates on a cost-of-service basis. Because such sellers will still only be making market-based sales, there is no reason to rescind the prior accounting and reporting waivers that were granted because they would only be making market-based rate sales. Cost-based sales of ancillary services have always been an option for third party sellers, and remain an option for them after issuance of this Final Rule. However, all of the requirements of cost-of-service regulation, such as the very accounting and reporting requirements at issue here, would apply to such sales. We also clarify that the requirement for a company to forego previously issued accounting and reporting waivers, in this instance, is only applicable when energy storage is involved. There may be other occasions when previously issued waivers may be rescinded however those occasions are outside the scope of this rulemaking.

b. Definition of Energy Storage Asset or Technology

171. EEI asks that the Commission clarify the definition of energy storage assets or technologies that are subject to these accounting and reporting requirements.[200] EEI proposes that the Commission define energy storage assets as "commercially available technology that is capable of absorbing energy, storing energy, and subsequently

[200] EEI Comments at 26-28.

releasing the energy to the electric system."[201] Further, EEI states that certain other energy storage assets should be exempted from the Final Rule, and thus the new accounts, if the function of the asset is so clearly related to activities properly reflected in existing accounts such that the asset is not designed to be used as an "energy storage asset" under the definition articulated in this Final Rule. EEI states, for example, that the following assets or technologies should be exempted:

> Batteries used primarily in connection with the control and switching of electric energy produced and the protection of electric circuits and equipment that are recorded in the following existing FERC accounts:
>
> > Account 315, Accessory Electric Equipment
> > Account 324, Accessory Electric Equipment (Major Only)
> > Account 345, Accessory Electric Equipment
>
> Batteries used in connection with controlling station equipment or for general station purposes that are recorded in the following existing FERC account:
>
> > Account 353, Station Equipment
>
> Batteries used in connection with controlling station equipment or for general station purposes that are recorded in the following existing FERC account:
>
> > Account 362, Station Equipment
>
> Compressed air systems used for pneumatic or air tools that are recorded in the following existing FERC accounts:
>
> > Account 316, Miscellaneous Power Plant Equipment

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[201] *Id.*

Account 325, Miscellaneous Power Plant Equipment
(Major Only)
Account 346, Miscellaneous Power Plant Equipment

Commission Determination

172. We agree with EEI that there are certain assets that are excluded from the scope of this Final Rule, however, we will not adopt EEI's proposed definition for an energy storage asset or technology. The definition is too broad and could be interpreted to include storage-type technologies that are outside the scope of this Final Rule. As EEI indicated, the assets listed above are the type of assets that should be excluded. This list is not exhaustive; rather it is an example of the type of assets and activities served by those assets that are a baseline indicator of assets that are outside the scope of the accounting and reporting requirements adopted in this Final Rule. For the purposes of this Final Rule, an energy storage asset shall be defined as property that is interconnected to the electrical grid and is designed to receive electrical energy, to store such electrical energy as another energy form,[202] and to convert such energy back to electricity and deliver such electricity for sale, or to use such energy to provide reliability or economic benefits to the grid. The term may include hydroelectric pumped storage and compressed air energy storage, regenerative fuel cells, batteries, superconducting magnetic energy

[202] Electrical energy may be converted to and stored as several different forms of energy such as chemical, mechanical, and thermal energies.

storage, flywheels, thermal energy storage systems, and hydrogen storage, or combination thereof, or any other technologies as the Commission may determine.[203]

c. Incorporating Energy Storage Plant Accounts into Existing Formula Rates

173. EEI requests that the Commission pre-authorize inclusion of the new energy storage plant and O&M expense accounts in existing formula rates without the need for separate, company-specific section 205 proceedings.[204] EEI contends that many jurisdictional utilities that own and operate energy storage technologies account for the assets in existing accounts that are incorporated in formula rates. EEI states that to the extent the new accounts require a revision to existing filed rates, the Commission should allow such changes to be filed in a compliance filing in this proceeding.

Commission Determination

174. We agree with EEI that utilities currently owning and operating these assets are using existing accounts and reporting schedules. Moreover, in many instances these accounts are incorporated in the companies' formula rate templates and costs reported in the accounts are through operation of the formula rate included in rate determinations. For some of these companies, transferring amounts from an existing plant account under

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[203] Although hydroelectric pumped storage is an energy storage technology in accordance with our definition, the accounting and reporting requirements of this rulemaking do not apply to the assets, notwithstanding the revisions to schedule pages 408-409. As we indicated previously, our existing accounting and reporting requirements for pumped storage sufficiently accommodate pumped storage assets and operations.

[204] EEI Comments at 32-33.

a particular functional classification to a new energy storage plant account under the same functional classification may involve a relatively straight-forward transfer of cost. In this type of situation, a compliance filing will provide adequate transparency to allow interested parties, including the Commission, to review amounts being transferred from one account to another and also to establish the incorporation of the new energy storage plant and O&M expense accounts in the formula rate tariff. However, a compliance filing may not be suitable for all situations.

175. For example, in instances where a company intends on recording the costs of an energy storage asset to multiple plant accounts in accordance with a plan to support multiple functions using the asset, a compliance filing may not provide for an adequate review of the many variables involved that can impact the determination of the appropriate allocation of the cost and rates charged based on the allocation. Moreover, if a company intends on recovering capital and O&M costs of the asset simultaneously under cost-based and market-based rate recovery mechanisms, a compliance filing would not provide sufficient notice or review of the cost to be recovered under the two rate mechanisms. Consequently, because a compliance filing is not appropriate for all situations, we will limit approval of its use to companies that are transferring amounts from an existing plant account under a particular functional classification to a new energy storage plant account under the same functional classification. Transfers of the costs to other plant accounts after this initial compliance filing shall be subject to the

requirements of Electric Plant Instruction No.12, Transfers of Property,[205] as proposed in the NOPR,[206] and the provisions of utilities' formula rate tariffs, as applicable. Utilities that do not qualify to use the compliance filing process must first receive approval from a relevant rate regulator to revise their existing formula rate tariffs to incorporate the new energy storage accounts.

d. Depreciation Rates for Energy Storage Assets

Commission Proposal

176. In the NOPR, the Commission proposed that the cost of energy storage assets be charged to depreciation expense using the depreciation rates developed for each function.[207]

Comments

177. Commenters generally support this proposal. For example, Beacon and ESA acknowledge support for the proposal.[208] EEI recommends that instead of requiring depreciation rates to be based on a utility's existing rate for a particular function, the Commission allow utilities to set initial depreciation rates for new energy storage battery equipment based on the manufacturer's estimated useful life, prior to the utilities receiving approval of new depreciation rates through a rate proceeding where new

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[205] 18 CFR Part 101 (2012).

[206] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 82.

[207] *Id*.

[208] Beacon Comments at 19; and ESA Comments at 19.

approved rates are ordered for these accounts.[209] EEI explains that the current life of storage batteries is expected to be approximately 10 to 15 years and it contends that this expected life can be substantially less than the life used to calculate the depreciation rate for the function the asset may be classified under.

Commission Determination

178. For accounting purposes, utilities are required to use percentage rates of depreciation that are based on a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property.[210] Where composite depreciation rates are used, the rate should be based on the weighted average estimated useful lives of depreciable property comprising the composite group. Furthermore, estimated service lives of depreciable property must be supported by engineering, economic, or other depreciation studies.[211] To the extent that an energy storage asset, such as a battery, has an estimated useful service life that is supported by engineering, economic, or other studies of the manufacturer or utility, the depreciation rate derived from such study must result in a systematic and rational allocation of the asset's costs over the estimated service life. Therefore, for accounting purposes, utilities may set initial rates for new energy storage assets based on

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[209] EEI Comments at 32.

[210] General Instruction No. 22, Depreciation Accounting, 18 CFR Part 101 (2012).

[211] *Id*.

manufacturer or utility estimated service lives that are supported by engineering, economic or other studies. In addition, as we indicated above, utilities should use a single depreciation rate for an energy storage asset regardless the number of functions to which the costs of the asset are allocated.[212]

e. Jurisdictional Authority

179. The California PUC warns that the Commission's authority over the accounting and reporting for energy storage assets should not limit or infringe upon States' jurisdictional authority over the assets as the majority of the assets are likely to be financed pursuant to state jurisdictional procurement authority.[213]

Commission Determination

180. The accounting and reporting requirements of this rulemaking are not intended to limit or infringe upon States' jurisdictional authority. Pursuant to section 301(a) of the Federal Power Act (FPA), the Commission has authority to prescribe a system of accounts and rules and regulations that are applicable in principle to all licensees and public utilities subject to the Commission's accounting and reporting requirements.[214] The Commission may determine the accounts in which particular outlays and receipts will be entered, charged or credited. The amendments to the accounting and reporting

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[212] *See supra* P 128.

[213] California PUC Comments at 8.

[214] 16 U.S.C. 825(a).

requirements are in accordance with the authority bestowed upon the Commission under the FPA and as such do not preempt or affect any jurisdiction a State commission or other State authority may have under applicable State and Federal law or limit the authority of a State commission in accordance with State and Federal law.

f. Implementation Date

181. EEI requests clarification of the implementation date of the proposed accounting and reporting requirements. EEI states that it believes assets and related amounts recorded in other accounts under the existing accounting requirements should be reclassified to the new energy storage accounts provided the asset meets the definition of an energy storage asset.[215] However, EEI argues that it would not be beneficial or cost effective to require utilities to retroactively amend prior year reports to implement the requirements. Therefore, EEI recommends that the accounting and reporting requirements be effective prospectively only.

Commission Determination

182. While we agree with EEI that it may not be cost effective to require utilities with energy storage assets to retroactively amend prior year reports to implement the accounting and reporting requirements of this Final Rule; we disagree with EEI's contention that it would not be beneficial to interested parties desiring more transparent reporting of the costs associated with energy storage operations. In these instances, the

[215] EEI Comments at 28-29.

Commission must weigh the perceived cost of implementing a requirement against the expected benefits of implementation. Although requiring utilities with energy storage assets to retroactively implement the requirements would provide a more transparent historical record of these utilities energy storage operations, this information would not be necessary to provide oversight of these utilities energy storage operations going forward. Moreover, it is not clear that the benefits of retroactive implementation are sufficient to justify the cost. Consequently, we will not require utilities to retroactively implement the accounting and reporting requirements.

183. Utilities subject to the Commission's accounting and reporting requirements must implement the requirements as of January 1, 2013. Utilities are not required to adjust prior year, comparative information reported in 2013 Form Nos. 1 and 1-F that must be filed by April 18, 2014, nor are they required to adjust prior year, comparative information reported in 2013 Form No. 3-Q reports. However, a footnote disclosure must be provided describing any amounts transferred from an existing account to a new energy storage account.

184. Due to outdated software, discussed in more detail below, the adopted new and revised schedules of Form Nos. 1, 1-F and 3-Q will not be available for use as of the effective date of this Final Rule. Consequently, utilities with energy storage assets and those that acquire the assets at a later date must continue or begin, as appropriate, using the existing form schedules to report energy storage assets pending availability of the new and revised schedules. Furthermore, we direct the Chief Accountant to issue interim accounting and reporting guidance for utilities to report to the Commission the costs of

energy storage operations contemplated in this Final Rule until the new and revised schedules are available.

185. Regarding the reporting software issues, the Commission's forms software applications are built with Visual FoxPro development tools and must be installed on a Windows-based computer. Microsoft, the Visual FoxPro vendor, announced in 2007 that it would no longer sell or issue new versions of Visual FoxPro and would provide support for it only through 2015. Also, over time, the Commission has found that it is difficult to update tables in the software to accommodate revisions to existing schedules and add new schedules to the forms because Visual FoxPro does not allow data tables to exceed two gigabytes. These data size limitations will soon restrict the Commission's ability to add data fields in the forms. These limitations make the forms software application outmoded, ineffective, and unsustainable.

186. Pursuant to Sections 141.1, 141.400, and 385.2011 of the Commission's Regulations,[216] Form Nos. 1 and 3-Q must be submitted using electronic media.[217] Due to technology changes that will render the current forms filing process outmoded, ineffective, and unsustainable, the Commission will discontinue the use of Commission-distributed software to file forms. Moreover, because of the software limitations, the new

[216] 18 CFR 141.1, 141.400, and 385.2011 (2012), respectively.

[217] Form No. 1-F filers may also submit the reports electronically; however, the Commission's regulations do not explicitly require these filers to submit the reports electronically. *See* 18 CFR 141.2 (2012).

and revised form schedules will not be available to utilities with energy storage assets and those that acquire the assets later as of the effective date of this Final Rule. Consequently, due to the time lag between implementation of the accounting and reporting requirements adopted here and the availability of a filing platform that accommodates the Commission's reporting forms, utilities should submit their 2013 Form No. 1 and 2014 Form No. 3-Qs using the existing forms filing process until an updated filing platform is made available by the Commission. Commission staff will issue appropriate notices and hold technical conferences if necessary concerning changes to the filing process.[218]

D. <u>Other Issues</u>

187. Some commenters raised issues beyond the scope of the NOPR. WSPP argues that public utility participation in a competitive market for ancillary services is hindered by certain OATT requirements applicable to network transmission customers. Specifically, WSPP refers to the requirement that network resources be undesignated as such, and thus lose their firm network transmission service, when they are committed to third-party sales instead of network load obligations. WSPP points to timing mismatches between the operational needs of ancillary service use and the undesignation

[218] Filers with energy storage assets and operations may be required to amend and refile their 2013 Form Nos. 1 and 1-F and 2014 Form No. 3-Q to report energy storage operation information in the schedules adopted in this final rule as a result of the anticipated new filing platform. However, these filers will not be required to amend and refile previously submitted 2013 Form No. 3-Qs.

requirements of the OATT as the main source of this issue. It argues that the Commission previously acknowledged these issues in connection with contingency reserves under the Southwest Reserve Sharing Group.[219] WSPP argues that this undesignation requirement hinders robust participation from network transmission customers, including the transmission providers themselves, in ancillary service markets.

188. EEI makes similar arguments with respect to the network resource undesignation requirements, and asks that the Commission remain receptive to utility-specific requests for flexibility.[220]

189. Hydro Association and Public Interest Organizations argue that the Commission should develop policies that facilitate long-term contracts with energy storage owners. Hydro Association asserts that the Commission should solicit further input on policies that would allow RTO, ISO, and stand-alone transmission providers to enter into long-term contracts with energy storage owners.[221] Public Interest Organizations make similar arguments.[222]

190. Shell Energy suggests that the current distinction between Energy Imbalance and Generator Imbalance is unnecessary, and that the two services should be combined into a single product. Shell Energy cites similar definitions in the EQR Data Dictionary, and

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[219] WSPP Comments at 19-21.

[220] EEI Comments 21-22.

[221] Hydro Association Comments at 4-6.

[222] Public Interest Organizations Comments at 11.

states that treating the two services as different products provides little benefit, creates unnecessary complexity and may result in confusion and regulatory uncertainty.[223]

191. Shell Energy also urges the Commission to recognize "Balancing Reserves" as a separate energy and capacity product used to firm variable energy resources. Shell Energy argues that such a product would be differentiated from ancillary services because, unlike ancillary services, it would not be limited to addressing contingencies. Shell Energy seeks clarification that such a product would not be considered an ancillary service, and thus would not be subject to the *Avista* restrictions. Rather it would be subject to a seller's existing authorization to sell energy and capacity at market-based rates.[224] EPSA makes similar arguments regarding the need for a new, non-contingency-related balancing reserves product.[225] While WSPP's comments do not specifically seek to identify a new product based on whether or not it can be used for issues other than contingencies, as do Shell Energy and EPSA, WSPP nevertheless makes certain similar arguments in part of its comments. WSPP asserts that sellers may not always wish to sell specific ancillary services, but rather may wish to sell "flexible capacity" products capable generally of fulfilling multiple OATT schedules. While its comments are not

[223] Shell Energy Comments at 3-4.

[224] Shell Energy Comments at 5-6.

[225] EPSA Comments at 10-11.

entirely clear on this point, WSPP could be interpreted to argue that the Commission should recognize flexible capacity as a product different from ancillary services.[226]

192. AWEA requests that the Commission explore the role that dynamic transfer capability, or lack thereof, plays in protecting against exertion of market power. AWEA argues that lack of dynamic transfer capability severely constrains competitive ancillary service markets in many parts of the country. AWEA suggests that the Commission could require transmission providers to analyze, inventory, and market dynamic scheduling capability on a non-discriminatory basis.[227]

193. Powerex argues that there may be certain locations where there is sufficient market liquidity such that a seller should be able to make ancillary service sales without performing a separate market power analysis. Powerex believes that these locations might be defined by some measure of market liquidity, or by a specific minimum number of potential sellers, and gives as examples the trading hubs of Mid-Columbia, California-Oregon Border, Palo Verde, Four Corners, and Mead. Powerex does not suggest specific liquidity metrics, but does have suggestions regarding the appropriate minimum number of potential suppliers. It suggests that third-party sales to a transmission provider could be deemed competitive any time there are: (1) at least three potential suppliers, each capable of providing 100 percent of the buyer's needs for the ancillary service in

[226] WSPP Comments at 7.

[227] AWEA Comments at 3.

question; or (2) at least five potential suppliers, each capable of meeting a significant portion (e.g., at least 25 percent) of the buyer's need for the ancillary service in question.

Commission Determination

194. With respect to WSPP's request for more flexibility on the requirements for network resource undesignation, the Commission declines to consider such changes on a generic basis at this time. This undesignation requirement is intended to ensure that network transmission customers cannot inappropriately withhold firm transmission capacity from potential competitors. While WSPP is correct that the Commission has permitted limited deviations from this requirement in connection with established reserve sharing groups, we are not persuaded that a more general relaxation is justified. WSPP indicates in its comments that a public utility is unable to undesignate the network resource providing the energy associated with the provision of ancillary services because the unit providing the energy may differ from the unit providing the capacity. This suggests that the public utility will be using transmission service from a unit that is different from the unit for which transmission service has been reserved. Thus, WSPP is essentially asking the Commission to permit a public utility transmission provider to implicitly use firm point-to-point transmission service without reserving it or paying for it. The Commission has previously expressly prohibited this practice and nothing in the comments suggests that the Commission's concerns are no longer valid.[228] Further,

[228] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 834.

participating in a reserve sharing group differs from making third-party market sales of ancillary services. A reserve sharing group essentially expands a public utility transmission provider's native load obligations to serving other load serving entities' native load in the event of a contingency with like protection in return. Permitting a public utility transmission provider to deliver energy associated with its reserve sharing group obligations without undesignating the resource providing the energy is an appropriate recognition of the network service elements of reserve sharing arrangements. On the other hand, market sales of ancillary services must be delivered using point-to-point transmission service.

195. With respect to the requests of Hydro Association and Public Interest Organizations to facilitate long-term contracting with energy storage owners, we see no basis for any additional action at this time. In bilateral markets, assuming that parties are able to avoid the *Avista* restrictions through use of one of the options provided in this rule, potential buyers including transmission owners and sellers are free to transact through contracts of whatever length they find mutually agreeable.

196. Shell Energy's suggestion that Energy Imbalance and Generator Imbalance services be combined into a single product is beyond the scope of this rulemaking, and Shell Energy's arguments in support of this idea do not rise to a level concrete enough to justify such an expansion at this time.

197. With respect to Shell Energy and EPSA's comments regarding recognition of non-contingency-related balancing reserves as separate from ancillary services, and WSPP's similar discussion of "flexible capacity," we clarify that sales of energy and capacity at

market-based rates are permissible, provided the buyer may not use the purchases to meet its OATT obligations to provide Regulation and Frequency Response or Reactive Supply and Voltage Control ancillary services.

198. AWEA's comments regarding dynamic transfer capability raise issues beyond the scope of this rulemaking, which have not been fully explored in this proceeding, and whose resolution is not necessary to the completion of this rulemaking. Accordingly, the Commission will not direct changes with respect to dynamic scheduling or dynamic transfer capability at this time.

199. Regarding Powerex's argument for development of a new market liquidity screen for ancillary service market power, we decline to attempt such development at this time. The record does not currently support either development of a generic market liquidity metric, or the particular minimum participant number thresholds proposed by Powerex. We remain open to a more detailed discussion of these ideas in the future if needed, but at this time will move forward with the rule changes contained elsewhere in this Final Rule, which we hope will reduce the need to develop alternative market power analyses.

III. Summary of Compliance and Implementation

200. With respect to this Final Rule's reforms to the *Avista* policy governing sales of certain ancillary services to a public utility purchasing the ancillary service to satisfy its own OATT requirements to offer ancillary services to its own customers, sellers that have a market-based rate tariff on file should revise the provision concerning third-party sales of ancillary services, to the extent they have this provision in their tariffs, as follows:

Third-party ancillary services: Seller offers [include all of the following that the seller is offering: Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning~~ Reserves~~, and Operating Reserve-Supplemental~~ Reserves~~]. Sales will not include the following: (1) sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier~~; and (3) sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers~~. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's

OATT rate for the same service or where the Commission has granted authorization.

201. While the authorization is effective as of the date specified in this Final Rule, sellers should file this tariff revision the next time they make a market-based rate filing with the Commission. To the extent sellers do not currently have this provision in their tariff but wish to make third-party sales of ancillary services, they should include this revised provision in their tariff the next time they make a market-based rate filing with the Commission.

202. With regard to sales of Operating Reserves, as discussed above, both sellers that have a market-based rate tariff on file and applicants seeking new market-based rate authority must satisfactorily make the required showing and receive Commission authorization before making sales of Operating Reserve-Spinning and Operating Reserve-Supplemental to a public utility that is purchasing Operating Reserve-Spinning and Operating Reserve-Supplemental to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.

203. With respect to the Final Rule's reforms to provide greater transparency with regard to reserve requirements for Regulation and Frequency Response, within 30 days from the effective date of this Final Rule, we require each public utility transmission provider to revise its OATT Schedule 3 consistent with the revised Schedule 3 in accordance with Appendix B to this Final Rule.

204. With respect to Final Rule's reforms to our accounting and reporting regulations, Utilities subject to these requirements must implement the requirements as of January 1,

2013. Utilities are not required to adjust prior year, comparative information reported in 2013 Form Nos. 1 and 1-F that must be filed by April 18, 2014, nor are they required to adjust prior year, comparative information reported in 2013 Form No. 3-Q reports. However, a footnote disclosure must be provided describing any amounts transferred from an existing account to a new energy storage account.

205. Due to outdated software, discussed in more detail in the body of this Final Rule, the adopted new and revised schedules of Form Nos. 1, 1-F and 3-Q will not be available for use as of the effective date of this Final Rule. Consequently, utilities with energy storage assets and those that acquire the assets at a later date must continue or begin, as appropriate, using the existing form schedules to report energy storage assets pending availability of the new and revised schedules.

IV. Information Collection Statement

206. The following collections of information contained in this Final Rule have been submitted to the Office of Management and Budget (OMB) for review under Section 3507(d) of the Paperwork Reduction Act of 1995.[229] OMB's regulations require approval of certain information collection requirements imposed by agency rule.[230] Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be

[229] *See* 44 U.S.C. 3507(d).

[230] 5 CFR 1320.11 (2012).

penalized for failing to respond to these collections of information if the collections of information do not display a valid OMB control number.

Burden Estimate: The additional estimated public reporting burdens and costs for the reporting requirements in this Final Rule are as follows. [231]

Data Collection	Number of Respondents (a)	Change in the Number of Hours Per Filing (averaging implementation over Yrs. 1-3)[232] (b) (hrs.)	Filings Per Respondent Per Year (c)	Change in the Total Annual Hours for this Collection (averaging implementation over Yrs. 1-3) (aXbXc=d) (hrs.)	Estimated Annual Cost (averaging implementation over Yrs. 1-3) (at $120/hr.) (dX$120/hr.) ($)
Form No. 1	210	7 [3 hrs. (one-time implementation in Year 1), plus 6 hrs. annually]	1	1,470	176,400
Form No. 1-F	5	7 [3 hrs. (one-time implementat	1	35	4,200

[231] In the NOPR, the Commission proposed changes to FERC-919 (related to the '20 percent screen'). The FERC-919 is not affected by the Final Rule. In addition, changes to FERC-516, which were not contained in the NOPR, are included in the Final Rule.

[232] For the Forms 1 and 1-F, the one-time implementation burden in Year 1 is estimated to be 3 hours per respondent. However, for the burden and cost estimates, we are averaging those additional 3 hours over Years 1-3, giving an average annual one-time implementation burden of 1 hour. That 1 hour is in addition to the normal annual filing burden of 6 hours each, giving an average annual estimate of 7 hours for Forms 1 and 1-F, for Years 1-3.

		ion in Year 1), plus 6 hrs. annually]			
Form No. 3-Q	213	1	3	639	76,680
FERC-917 [includes one-time filing of Pro forma open-access transmission tariff (OATT) & data sharing] [233]	132	17.33 averaged over Years 1-3 [4 hrs. one-time in Yr. 1, plus an average recurring burden in Years 1-3 of 16 hrs.]	1	2,288 averaged over Years 1-3	274,560 averaged over Years 1-3
FERC-516	no change	no change	no change	no change	no change
FERC-717 (OASIS posting under 18 CFR	176	1	1	176	9,889[234]

[233] This includes the one-time refiling of OATT Schedule 3 (estimated average of 4 hours per utility respondent), and if requested, the utility's sharing data and a narrative description with its self-supplying customer(s) (estimated average of 4 customer requests per utility respondent per year, taking 4 hours per request). The estimated annual burden per utility is

- Year 1: 4 hrs. (for one-time refiling) + (4 requests * 4 hrs.), giving an estimate of 20 hrs. per utility
- Years 2 and 3, each: 4 requests * 4 hrs., giving 16 hrs. per utility per year.

When the one-time implementation burden (of 4 hours) is averaged over Years 1-3, the annual additional burden per utility is 17.33 hours.

[234] Based on the 2012 data from the Bureau of Labor Statistics at http://bls.gov/oes/current/naics2_22.htm, the hourly cost of salary plus benefits would be $56.19.

37.6k)					
Total				4,608 (averaged over Years 1-3)	$541,729 (averaged over Years 1-3)

In paragraph 96, the Commission is requiring that any third-party seller seeking to sell ancillary services to a public utility transmission provider through a competitive solicitation will need to demonstrate compliance with the competitive solicitation requirements of this rule, through a filing under section 205 of the Federal Power Act. This requirement for submittal in a section 205 filing would be made under FERC-516 (OMB Control No. 1902-0096). The filing would be submitted by the seller to the Commission prior to commencement of service under the third-party ancillary service sales agreement that results from the competitive solicitation. The filing will include both the actual sales agreement and a narrative description of how the buyer's competitive solicitation meets the requirements of this Final Rule. Meeting those requirements demonstrates the justness and reasonableness of the resulting rate. If the seller did not have this option to sell under the competitive solicitation, the seller could not use market-based rates and would have to either submit an application for cost-based rates under FERC-516 or an application seeking waiver of the *Avista* restrictions on a case-by-case basis.[235] The Commission believes that the burden associated with the new requirements is far less burden than a full cost-of-service rate filing and approximately

[235] *See, e.g., Powerex*, 125 FERC ¶ 61,179 (2008).

the same burden as the burden associated with an *Avista* waiver filing. In addition, the numbers of respondents and filings are not expected to change significantly. Therefore, no changes are proposed to the burden or number of responses for FERC-516.

Title: FERC Form No. 1, "Annual Report of Major Electric Utilities, Licensees, and Others;" FERC Form No. 1-F, "Annual Report for Nonmajor Public Utilities and Licensees;" FERC Form No. 3-Q, "Quarterly Financial Report of Electric Utilities, Licensees and Natural Gas Companies;" FERC-917, "Non-discriminatory Open Access Transmission Tariff;" FERC-516, " Electric Rate Schedules and Tariff Filings," and FERC-717, "Open Access Same-Time Information System and Standards for Business Practices & Communication Protocols."

Action: Proposed revisions to information collections.

OMB Control Nos.: 1902-0021 (FERC Form No. 1); 1902-0029 (FERC Form No. 1-F); 1902-0205 (FERC Form No. 3-Q); 1902-0233 (FERC-917), 1902-0096 (FERC-516), and 1902-0173 (FERC-717).

Respondents: Businesses or other for profit and/or not-for-profit institutions.

Frequency of responses: Annually (FERC Form Nos. 1 and 1-F, and FERC-717); quarterly (FERC Form No. 3-Q); and as needed (FERC-917 and FERC-516).

Necessity of the Information: The final rule amends the Commission's regulations to reflect changes that are occurring in the electric industry due to the availability of new energy storage technologies that are being used in the provision of large-scale utility operations. These technologies are providing services that were typically provided by traditional single-purpose production, transmission and distribution resources. The addition of these new plant accounts and new and amended reporting forms are intended to enhance transparency and provide detailed information on transactions and events affecting public utilities and licensees that file reports with the Commission. The accounting regulations currently found in the USofA and related reporting requirements capture financial and operational information along traditional primary business functions but do not provide sufficient detailed information concerning energy storage operations, and in particular, the costs incurred by organizations using these resources to simultaneously provide multiple utility services with a single asset. The addition of these accounts is intended to improve the transparency, completeness and consistency of accounting practices for the cost of assets, the expenses incurred in providing services, along with revenues collected. Without specific instructions and accounts for recording and reporting the above transactions and events, inconsistent and incomplete accounting and reporting will result.

Internal Review: The Commission has reviewed the requirements pertaining to the USofA and to the reports it prescribes and determined that the proposed amendments are necessary because the Commission needs to establish uniform accounting and reporting requirements for the costs of utility assets and the expenses incurred for providing services as part of its operations.

These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements.

Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426 [Attention: Ellen Brown, Office of the Executive Director], e-mail: DataClearance@ferc.gov, Phone (202) 502-8663, fax: (202) 273-0873.

Comments on the collection of information and the associated burden estimates in the rule should be sent to the Commission in this docket and may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments to OMB should be submitted by e-mail to: oira_submission@omb.eop.gov. Please refer to OMB Control Nos. 1902-0021 (FERC Form No. 1), 1902-0029 (FERC Form No. 1-F), 1902-0205 (FERC Form No. 3-Q), and 1902-0233 (FERC-917), 1902-0096 (FERC-516), and 1902-0173 (FERC-717) and Docket Number RM11-24.

V. Environmental Analysis

207. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect

on the human environment.[236] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Final Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale subject to the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classifications, and services.[237]

VI. Regulatory Flexibility Act

208. The Regulatory Flexibility Act of 1980 (RFA)[238] generally requires a description and analysis of rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[239] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission,

[236] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[237] 18 CFR 380.4(a)(15) (2012).

[238] 5 U.S.C. 601-612.

[239] 13 CFR 121.101 (2011).

generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[240] The rule applies exclusively to public utilities that own, control, or operate facilities for transmitting electric energy in interstate commerce and not electric utilities per se. Based on the filers of the 2011 annual FERC Form No. 1 and Form No. 1-F, as well as the number of companies that have obtained waivers, we estimate that 44 entities (20 percent of the filers) affected by this proposed rule are "small." For each of the 44 "small" entities, the Commission estimates an additional annual burden of only ten hours (seven hours for the annual Form 1 or Form 1-F (averaging implementation over years 1-3), plus one hour per quarter for the Form 3-Q). The Commission believes this rule will not have a significant economic impact on a substantial number of small entities, and therefore no regulatory flexibility analysis is required.

VII. Document Availability

209. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

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[240] 13 CFR 121.201, Sector 22, Utilities.

210. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number, excluding the last three digits of this document in the docket number field.

211. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. Email the Public Reference Room at public.referenceroom@ferc.gov.

Effective Date and Congressional Notification. These regulations are effective **[insert date 120 days from publication in Federal Register]**. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

<u>List of subjects in 18 CFR Parts 35, 101 and 141</u>
Electric power rates; Electric utilities; Electric power; Uniform System of Accounts

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

In consideration of the foregoing, the Commission proposes to amend Parts 35 and 101,

Chapter I, Title 18, Code of Federal Regulations, as follows.

PART 35 – FILING OF RATE SCHEDULES AND TARIFFS

1. The authority citation for Part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 7101-7352.

2. Amend § 35.37 by revising subsection (c)(1) as follows.

§ 35.37 Market power analysis required.

* * * * *

(c)(1) There will be a rebuttable presumption that a Seller lacks horizontal market power with respect to sales of energy, capacity, energy imbalance, generator imbalance, operating reserve-spinning, and operating reserve-supplemental services if it passes two indicative market power screens: a pivotal supplier analysis based on annual peak demand of the relevant market, and a market share analysis applied on a seasonal basis. There will be a rebuttable presumption that a seller possesses horizontal market power with respect to sales of energy, capacity, energy imbalance, generator imbalance, operating reserve-spinning, and operating reserve-supplemental services if it fails either screen.

* * * * *

3. Amend § 35.38 as follows:

a. Paragraph (a) is revised.

b. Paragraph (b) is revised.

c. New paragraph (c) is added.

§ **35.38 Mitigation**.

* * * * *

(a) A Seller that has been found to have market power in generation or ancillary services, or that is presumed to have horizontal market power in generation or ancillary services by virtue of failing or foregoing the relevant market power screens, as described in 35.37(c), may adopt the default mitigation detailed in paragraph (b) of this section for sales of energy or capacity or paragraph (c) of this section for sales of ancillary services or may propose mitigation tailored to its own particular circumstances to eliminate its ability to exercise market power. Mitigation will apply only to the market(s) in which the Seller is found, or presumed, to have market power.

(b) Default mitigation for sales of energy or capacity consists of three distinct products:

* * * * *

(c) Default mitigation for sales of ancillary services consist of: (1) a cap based on the relevant OATT ancillary service rate of the purchasing transmission operator; or (2) the results of a competitive solicitation that meets the Commission's requirements for transparency, definition, evaluation, and competitiveness.

4. Amend § 37.6 by adding a new paragraph (k) as follows:

§ **37.6 Information to be posted on the OASIS**.

* * * * *

(k) *Posting of historical area control error data.* The Transmission Provider must post on OASIS historical one-minute and ten-minute area control error data for the most recent calendar year, and update this posting once per year.

PART 101 - UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT

5. The authority citation for Part 101 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 7101-7352, 7651-7651o.

6. In Part 101, Electric Plant Chart of Accounts, Account 348 is added to the list:

Electric Plant Chart of Accounts

* * * * *

2. PRODUCTION PLANT

* * * * *

D. OTHER PRODUCTION

* * * * *

348 Energy Storage Equipment-Production

* * * * *

7. In Part 101, Electric Plant Accounts, Account 351, the name of the account is amended and instructions are added to read as follows:

Electric Plant Accounts

* * * * *

351 Energy Storage Equipment-Transmission

A. This account shall include the cost installed of energy storage equipment used to store energy for load managing purposes. Where energy storage equipment can perform more than one function or purposes, the cost of the equipment shall be allocated among production, transmission, and distribution plant based on the services provided by the asset and the allocation of the asset's cost through rates approved by a relevant regulatory agency. Reallocation of the cost of equipment recorded in this account shall be in accordance with Electric Plant Instruction No. 12, Transfers of Property.

B. Labor costs and power purchased to energize the equipment are includible on the first installation only. The cost of removing, relocating and resetting energy storage equipment shall not be charged to this account but to Account 562.1, Operation of Energy Storage Equipment, and Account, 570.1, Maintenance of Energy Storage Equipment, as appropriate.

C. The records supporting this account shall show, by months, the function(s) each energy storage asset supports or performs.

ITEMS

1. Batteries/Chemical

2. Compressed Air

3. Flywheels

4. Superconducting Magnetic Storage

5. Thermal

8. In Part 101, Electric Plant Accounts, Account 363, the name of the account and the instructions are amended to read as follows:

Electric Plant Accounts

* * * * *

363 Energy Storage Equipment-Distribution

A. This account shall include the cost installed of energy storage equipment used to store energy for load managing purposes. Where energy storage equipment can perform more than one function or purpose, the cost of the equipment shall be allocated among production, transmission, and distribution plant based on the services provided by the asset and the allocation of the asset's cost through rates approved by a relevant regulatory agency. Reallocation of the cost of equipment recorded in this account shall be in accordance with Electric Plant Instruction No. 12, Transfers of Property.

B. Labor costs and power purchased to energize the equipment are includible on the first installation only. The cost of removing, relocating and resetting energy storage equipment shall not be charged to this account but to Account 582.1, Operation of Energy Storage Equipment, and Account, 592.1, Maintenance of Energy Storage Equipment, as appropriate.

C. The records supporting this account shall show, by months, the function(s) each energy storage asset supports or performs.

ITEMS

1. Batteries/Chemical
2. Compressed Air
3. Flywheels
4. Superconducting Magnetic Storage
5. Thermal

9. In Part 101, Electric Plant Accounts, new primary plant account 348 is added to read as follows:

Electric Plant Accounts

* * * * *

348, Energy Storage Equipment-Production

A. This account shall include the cost installed of energy storage equipment used to store energy for load managing purposes. Where energy storage equipment can perform more than one function or purpose, the cost of the equipment shall be allocated among production, transmission, and distribution plant based on the services provided by the asset and the allocation of the asset's cost through rates approved by a relevant regulatory agency. Reallocation of the cost of equipment recorded in this account shall be in accordance with Electric Plant Instruction No. 12, Transfers of Property.

B. Labor costs and power purchased to energize the equipment are includible on the first installation only. The cost of removing, relocating and resetting energy storage equipment shall not be charged to this account but to accounts Account 548.1, Operation of Energy Storage Equipment, and Account 553.1, Maintenance of Energy Storage Equipment., as appropriate.

C. The records supporting this account shall show, by months, the function(s) each energy storage asset supports or performs.

ITEMS

1. Batteries/Chemical
2. Compressed Air
3. Flywheels
4. Superconducting Magnetic Storage
5. Thermal

NOTE: The cost of pumped storage hydroelectric plant shall be charged to hydraulic production plant. These are examples of items includible in this account. This list is not exhaustive.

10. In Part 101, Operation and Maintenance Expense Chart of Accounts, Accounts 548.1, 553.1, 555.1, 562.1, 570.1, 584.1, and 592.2 are added to the list:

Operation and Maintenance Expense Chart of Accounts

* * * * *

1. POWER PRODUCTION EXPENSES

* * * * *

D. OTHER POWER GENERATION

* * * * *

Operation

* * * * *

548.1 Operation of Energy Storage Equipment

* * * * *

Maintenance

553.1 Maintenance of Energy Storage Equipment

* * * * *

E. OTHER POWER SUPPLY EXPENSES

* * * * *

555.1 Power Purchased for Storage Operations

* * * * *

2. TRANSMISSION EXPENSES

* * * * *

Operation

* * * * *

562.1 Operation of Energy Storage Equipment

* * * * *

Maintenance

* * * * *

570.1 Maintenance of Energy Storage Equipment

* * * * *

4. DISTRIBUTION EXPENSES

* * * * *

Operation

* * * * *

584.1 Operation of Energy Storage Equipment

* * * * *

Maintenance

* * * * *

592.2 Maintenance of Energy Storage Equipment

11. In Part 101, Operation and Maintenance Expense Accounts, new operation expense account 548.1 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

548.1 Operation of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the operation of energy storage equipment includible in Account 348, Energy Storage Equipment-Production, which are not specifically provided for or are readily assignable to other production operation expense accounts.

12. In Part 101, Operation and Maintenance Expense Accounts, new maintenance expense account 553.1 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

553.1 Maintenance of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of energy storage equipment includible in Account 348, Energy

Storage Equipment-Production, which are not specifically provided for or are readily assignable to other production maintenance expense accounts.

13. In Part 101, Operation and Maintenance Expense Accounts, new power supply expense account 555.1 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

555.1 Power Purchased for Storage Operations

A. This account shall include the cost at point of receipt by the utility of electricity purchased for use in storage operations, including power purchased and consumed or lost in energy storage operations during the provision of services, including but not limited to energy purchased and stored for resale. It shall also include but not be limited to net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, and spinning reserve capacity. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, capacity, and possibly other factors. Distinct purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.

B. The records supporting this account shall show, by months, the kilowatt hours and prices thereof under each purchase contract and the charges and credits under each exchange or power pooling contract.

14. In Part 101, Operation and Maintenance Expense Accounts, new operation expense account 562.1 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

562.1 Operation of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the operation of energy storage equipment includible in Account 351, Energy Storage Equipment-Transmission, which are not specifically provided for or are readily assignable to other transmission operation expense accounts.

15. In Part 101, Operation and Maintenance Expense Accounts, new maintenance expense account 570.1 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

570.1 Maintenance of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of energy storage equipment includible in Account 351, Energy Storage Equipment-Transmission, which are not specifically provided for or are readily assignable to other transmission maintenance expense accounts.

16. In Part 101, Operation and Maintenance Expense Accounts, new operation expense account 584.1 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

584.1 Operation of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the operation of energy storage equipment includible in Account 363, Energy Storage Equipment-Distribution, which are not specifically provided for or are readily assignable to other distribution operation expense accounts.

17. In Part 101, Operation and Maintenance Expense Accounts, new maintenance expense account 592.2 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

592.2 Maintenance of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of energy storage equipment includible in Account 363, Energy Storage Equipment-Distribution, which are not specifically provided for or are readily assignable to other distribution maintenance expense accounts.

18. In Part 101, Operation and Maintenance Expense Accounts, maintenance expense account 592 is amended to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

592 Maintenance of Station Equipment (Major only)

This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which is includible in account 362, Station Equipment. (See operating expense instruction 2.)

19. In Part 101, Operation and Maintenance Expense Accounts, maintenance expense account 592.1 is amended to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

592.1 Maintenance of Structures and Equipment (Nonmajor only)

This account shall include the cost of labor, materials used and expenses incurred in maintenance of structures, the book cost of which is includible in account 361, Structures and Improvements, and account 362, Station Equipment. (See operating expense instruction 2.)

Note: The following appendix will not be published in the *Code of Federal Regulations*.

Appendix A: List of Short Names of Commenters on the Federal Energy Regulatory Commission's Notice of Proposed Rulemaking on Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies – Docket No. RM11-24-000, June 2012

Short Name or Acronym	Commenter
APPA	American Public Power Association
AWEA	American Wind Energy Association
Beacon	Beacon Power Corporation
California PUC	California Public Utilities Commission
California Storage Alliance	California Energy Storage Alliance
EEI	Edison Electric Institute
Electricity Consumers	Electricity Consumers Resource Council
ENBALA	ENBALA Power Networks
EPSA	Electric Power Supply Association
ESA	Electricity Storage Association
FTC Staff	Staff of the Federal Trade Commission
Hydro Association	National Hydropower Association
Iberdrola	Iberdrola Renewables, LLC
Indicated Suppliers	Calpine Corporation, Dynegy Inc., Exelon Corporation, GenOn Energy, Inc., and Tenaska Energy, Inc.
Midwest ISO	Midwest Independent Transmission System Operator Inc.
Morgan Stanley	Morgan Stanley Capital Group Inc.
NAATBatt	National Alliance for Advanced

	Technology Batteries
New York ISO	New York Independent System Operator, Inc.
NU Companies	Northeast Utilities Service Company on behalf of Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and NSTAR Electric Company
Powerex	Powerex Corporation
Public Interest Organizations	Center for Rural Affairs, Clean Wisconsin, Climate + Energy Project, Conservation Law Foundation, Environment Northeast, Fresh Energy, Land Trust Alliance, Natural Resources Defense Council, Pace Energy and Climate Center, Project for Sustainable FERC Energy Policy, Sierra Club and Union of Concerned Scientists
Public Power Council	Public Power Council
SDG&E	San Diego Gas & Electric Company
Shell Energy	Shell Energy North America (US), L.P.
Solar Energy Association	Solar Energy Industries Association
Southern California Edison	Southern California Edison Company
TAPS	Transmission Access Policy Study Group and Transmission Dependent Utility Systems
Western Group	Arizona Public Service, Avista Corporation, Bonneville Power Administration, Idaho Power Company, PacifiCorp, Portland General Electric, Xcel Energy Services, Puget Sound

	Energy, Inc., Seattle City Light, and Takoma Power
WSPP	WSPP, Inc.

NOTE: The following Appendix will not be published in the *Code of Federal Regulations*.

Appendix B: *Pro Forma* Open Access Transmission Tariff

The Commission amends Schedule 3, Regulation and Frequency Response Service of the *pro forma* OATT:

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying

Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

NOTE: The following Appendix will not be published in the *Code of Federal Regulations*.

Appendix C – New and Amended Form 1/1F/3Q Pages.

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of Year/Qtr

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none", "not applicable", or "NA", as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none", "not applicable", or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant and Accumulated Provisions for Dep, Amort and Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228-229	
24	Extraordinary Property Losses	230	
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

FERC FORM NO. 1 (REV. 12-12) **Page 2**
FERC FORM NO. 1-F (REV. 12-12)

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of Year/Qtr

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none", "not applicable", or "NA", as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none", "not applicable", or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	
56	Amounts included in ISO/RTO Settlement Statements	397	
57	Purchase and Sale of Ancillary Services	398	
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	
63	Hydroelectric Generating Plant Statistics	406-407	
64	Pumped Storage Generating Plant Statistics	408-409	
65	Generating Plant Statistics Pages	410-411	
66	Energy Storage Operations (Large Plants)	414-416	
67	Energy Storage Operations (Small Plants)	419-420	

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of Year/Qtr

LIST OF SCHEDULES (Electric Utility) (Continued)

Enter in column (c) the terms "none", "not applicable", or "NA", as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none", "not applicable", or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
68	Transmission Line Statistics Pages	426-427	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
72	Stockholder's Reports – Check appropriate box: □ Two copies will be submitted. □ No annual report to stockholders is prepared.		

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ______

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Accounts (a)	Balance Beginning of Year (b)	Additions (c)
1	**1. INTANGIBLE PLANT**		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)		
6	**2. PRODUCTION PLANT**		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)		
17	**B. Nuclear Production Plant**		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	**C. Hydraulic Production Plant**		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Miscellaneous Power Plant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	**D. Other Production Plant**		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production		
45	(348) Energy Storage Equipment - Production		
46	TOTAL Other Production Plant (Enter Total of lines 37 thru 45)		
47	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 46)		

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
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Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Accounts (a)	Balance Beginning of Year (b)	Additions (c)
48	**3. TRANSMISSION PLANT**		
49	(350) Land and Land Rights		
50	(351) Energy Storage Equipment - Transmission		
51	(352) Structures and Improvements		
52	(353) Station Equipment		
53	(354) Towers and Fixtures		
54	(355) Poles and Fixtures		
55	(356) Overhead Conductors and Devices		
56	(357) Underground Conduit		
57	(358) Underground Conductors and Devices		
58	(359) Roads and Trails		
59	(359.1) Asset Retirement Costs for Transmission Plant		
60	TOTAL Transmission Plant (Enter Total of lines 49 thru 59)		
61	**4. DISTRIBUTION PLANT**		
62	(360) Land and Land Rights		
63	(361) Structures and Improvements		
64	(362) Station Equipment		
65	(363) Energy Storage Equipment – Distribution		
66	(364) Poles, Towers, and Fixtures		
67	(365) Overhead Conductors and Devices		
68	(366) Underground Conduit		
69	(367) Underground Conductors and Devices		
70	(368) Line Transformers		
71	(369) Services		
72	(370) Meters		
73	(371) Installations on Customer Premises		
74	(372) Leased Property on Customer Premises		
75	(373) Street Lighting and Signal Systems		
76	(374) Asset Retirement Costs for Distribution Plant		
77	TOTAL Distribution Plant (Enter Total of lines 62 thru 76)		
78	**5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT**		
79	(380) Land and Land Rights		
80	(381) Structures and Improvements		
81	(382) Computer Hardware		
82	(383) Computer Software		
83	(384) Communication Equipment		
84	(385) Miscellaneous Regional Transmission and Market Operation Plant		
85	(386) Asset Retirement Costs for Regional Transmission and Market Operation Plant		
86	TOTAL Transmission and Market Operation Plant (Enter Total of lines 79 thru 85)		
87	**6. GENERAL PLANT**		
88	(389) Land and Land Rights		
89	(390) Structures and Improvements		
90	(391) Office Furniture and Equipment		
91	(392) Transportation Equipment		
92	(393) Stores Equipment		
93	(394) Tools, Shop and Garage Equipment		
94	(395) Laboratory Equipment		
95	(396) Power Operated Equipment		
96	(397) Communication Equipment		
97	(398) Miscellaneous Equipment		
98	SUBTOTAL (Enter Total of Lines 88 thru 97)		
99	(399) Other Intangible Property		
100	(399.1) Asset Retirement Costs for General Plant		
101	TOTAL General Plant (Enter Total of Lines 98, 99 and 100)		
102	TOTAL (Accounts 101 and 106)		
103	(102) Electric Plant Purchased (See Instruction 8)		
104	(Less) (102) Electric Plant Sold (See Instruction 8)		
105	(103) Experimental Plant Unclassified		
106	TOTAL Electric Plant in Service (Enter Total of lines 102 thru 1051)		

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
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Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	**1. POWER PRODUCTION EXPENSES**		
2	**A. Steam Power Generation**		
3	**Operation**		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	**Maintenance**		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Enter Total lines 13 & 20)		
22	**B. Nuclear Power Generation**		
23	**Operation**		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	**Maintenance**		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 & 40)		
42	**C. Hydraulic Power Generation**		
43	**Operation**		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
52	**Maintenance**		
53	(541) Maintenance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 and 58)		

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ______

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Accounts (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	**D. Other Power Generation**		
61	**Operation**		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(548.1) Operation of Energy Storage Equipment		
66	(549) Miscellaneous Other Power Generation Expenses		
67	(550) Rents		
68	TOTAL Operation (Enter Total of lines 62 thru 67)		
69	**Maintenance**		
70	(551) Maintenance Supervision and Engineering		
71	(552) Maintenance of Structures		
72	(553) Maintenance of Generating and Electric Plant		
73	(553.1) Maintenance of Energy Storage Equipment		
74	(554) Maintenance of Miscellaneous Other Power Generation Plant		
75	TOTAL Maintenance (Enter Total of lines 70 thru 74)		
76	TOTAL Power Production Expenses-Other Power (Enter Total of lines 68 & 75)		
77	**E. Other Power Supply Expenses**		
78	(555) Purchased Power		
79	(555.1) Power Purchased for Storage Operations		
80	(556) System Control and Load Dispatching		
81	(557) Other Expenses		
82	TOTAL Other Power Supply Expenses (Enter Total of lines 78 thru 81)		
83	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 76 & 82)		
84	**2. TRANSMISSION EXPENSES**		
85	**Operation**		
86	(560) Operation Supervision and Engineering		
87	(561.1) Load Dispatch-Reliability		
88	(561.2) Load Dispatch-Monitor and Operate Transmission System		
89	(561.3) Load Dispatch-Transmission Service and Scheduling		
90	(561.4) Scheduling, System Control and Dispatch Services		
91	(561.5) Reliability, Planning and Standards Development		
92	(561.6) Transmission Service Studies		
93	(561.7) Generation Interconnection Studies		
94	(561.8) Reliability, Planning and Standards Development Services		
95	(562) Station Expenses		
96	(562.1) Operation of Energy Storage Equipment		
97	(563) Overhead Lines Expenses		
98	(564) Underground Lines Expenses		
99	(565) Transmission of Electricity by Others		
100	(566) Miscellaneous Transmission Expenses		
101	(567) Rents		
102	TOTAL Operation (Enter Total of lines 85 thru 101)		
103	**Maintenance**		
104	(568) Maintenance Supervision and Engineering		
105	(569) Maintenance of Structures		
106	(569.1) Maintenance of Computer Hardware		
107	(569.2) Maintenance of Computer Software		
108	(569.3) Maintenance of Communication Equipment		
109	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
110	(570) Maintenance of Station Equipment		
111	(570.1) Maintenance of Energy Storage Equipment		
112	(571) Maintenance of Overhead Lines		
113	(572) Maintenance of Underground Lines		
114	(573) Maintenance of Miscellaneous Transmission Plant		

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
115	TOTAL Maintenance (Enter Total of lines 104 thru 114)		
116	TOTAL Transmission Expenses (Enter Total of lines 102 and 115)		
117	**3. REGIONAL MARKET EXPENSES**		
118	**Operation**		
119	(575.1) Operation Supervision		
120	(575.2) Day-Ahead and Real-Time Market Facilitation		
121	(575.3) Transmission Rights Market Facilitation		
122	(575.4) Capacity Market Facilitation		
123	(575.5) Ancillary Services Market Facilitation		
124	(575.6) Market Monitoring and Compliance		
125	(575.7) Market Facilitation, Monitoring and Compliance Services		
126	(575.8) Rents		
127	Total Operation (Lines 119 thru 126)		
128	**Maintenance**		
129	(576.1) Maintenance of Structures and Improvements		
130	(576.2) Maintenance of Computer Hardware		
131	(576.3) Maintenance of Computer Software		
132	(576.4) Maintenance of Communication Equipment		
133	(576.5) Maintenance of Miscellaneous Market Operation Plant		
134	Total Maintenance (Lines 129 thru 133)		
135	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of lines 127 and 134)		
136	**4. DISTRIBUTION EXPENSES**		
137	**Operation**		
138	(580) Operation Supervision and Engineering		
139	(581) Load Dispatching		
140	(582) Station Expenses		
141	(583) Overhead Line Expenses		
142	(584) Underground Line Expenses		
143	(584.1) Operation of Energy Storage Equipment		
144	(585) Street Lighting and Signal System Expenses		
145	(586) Meter Expenses		
146	(587) Customer Installations Expenses		
147	(588) Miscellaneous Expenses		
148	(589) Rents		
149	TOTAL Operation (Enter Total of lines 138 thru 148)		
150	**Maintenance**		
151	(590) Maintenance Supervision and Engineering		
152	(591) Maintenance of Structure		
153	(592) Maintenance of Station Equipment		
154	(592.1) Maintenance of Structures and Equipment		
155	(592.2) Maintenance of Energy Storage Equipment		
156	(593) Maintenance of Overhead Lines		
157	(594) Maintenance of Underground Lines		
158	(595) Maintenance of Line Transformers		
159	(596) Maintenance of Street Lighting and Signal Systems		
160	(597) Maintenance of Meters		
161	(598) Maintenance of Miscellaneous Distribution Plant		
162	TOTAL Maintenance (Enter Total of lines 151 thru 161)		
163	TOTAL Distribution Expenses (Enter Total of lines 149 and 162)		

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
163	**5. CUSTOMER ACCOUNTS EXPENSES**		
164	**Operation**		
165	(901) Supervision		
166	(902) Meter Reading Expenses		
167	(903) Customer Records and Collection Expenses		
168	(904) Uncollectible Accounts		
169	(905) Miscellaneous Customer Accounts Expenses		
170	TOTAL Customer Accounts Expenses (Total of lines 165 thru 169)		
171	**6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES**		
172	**Operation**		
173	(907) Supervision		
174	(908) Customer Assistance Expenses		
175	(909) Informational and Instructional Expenses		
176	(910) Miscellaneous Customer Service and Informational Expenses		
177	TOTAL Customer Service and Information. Expenses (Total lines 173 thru 176)		
178	**7. SALES EXPENSES**		
179	**Operation**		
180	(911) Supervision		
181	(912) Demonstrating and Selling Expenses		
182	(913) Advertising Expenses		
183	(916) Miscellaneous Sales Expenses		
184	TOTAL Sales Expenses (Enter Total of lines 180 thru 184)		
185	**8. ADMINISTRATIVE AND GENERAL EXPENSES**		
186	**Operation**		
187	(920) Administrative and General Salaries		
188	(921) Office Supplies and Expenses		
189	(Less) (922) Administrative Expenses Transferred-Credit		
190	(923) Outside Services Employed		
191	(924) Property Insurance		
192	(925) Injuries and Damages		
193	(926) Employee Pensions and Benefits		
194	(927) Franchise Requirements		
195	(928) Regulatory Commission Expenses		
196	(929) (Less) Duplicate Charges-Cr.		
197	(930.1) General Advertising Expenses		
198	(930.2) Miscellaneous General Expenses		
199	(931) Rents		
200	TOTAL Operation (Enter Total of lines 187 thru 199)		
201	**Maintenance**		
202	(935) Maintenance of General Plant		
203	TOTAL Administrative & General Expenses (Total of lines 199 and 201)		
204	TOTAL Electric Operation and Maintenance Expenses (Total of lines 83, 116, 135, 162, 170, 177, 184, and 203)		

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC PRODUCTION, OTHER POWER SUPPLY, TRANSMISSION, **REGIONAL MARKET,** AND DISTRIBUTION EXPENSES

Report Electric production, other power supply expenses, transmission, regional market, and distribution expenses through the reporting period.

Line No.	Account (a)	Year to Date Quarter
1	**1. POWER PRODUCTION AND OTHER SUPPLY EXPENSES**	
2	Steam Power Generation - Operation (500-509)	
3	Steam Power Generation – Maintenance (510-515)	
4	Total Power Production Expenses - Steam Power	
5	Nuclear Power Generation – Operation (517-525)	
6	Nuclear Power Generation – Maintenance (528-532)	
7	Total Power Production Expenses - Nuclear Power	
8	Hydraulic Power Generation – Operation (535-540.1)	
9	Hydraulic Power Generation – Maintenance (541-545.1)	
10	Total Power Production Expenses - Hydraulic Power	
11	Other Power Generation – Operation (546-550.1)	
12	Other Power Generation – Maintenance (551-554.1)	
13	Total Power Production Expenses - Other Power	
14	**Other Power Supply Expenses**	
15	Purchased Power (555)	
16	Power Purchased for Storage Operations (555.1)	
17	System Control and Load Dispatching (556)	
18	Other Expenses (557)	
19	Total Other Power Supply Expenses (line 15-18)	
20	Total Power Production Expenses (Total of lines 4, 7, 10, 13 and 19)	
21	**2. TRANSMISSION EXPENSES**	
22	**Transmission Operation Expenses**	
23	(560) Operation Supervision and Engineering	
24	(561.1) Load Dispatch-Reliability	
25	(561.2) Load Dispatch-Monitor and Operate Transmission System	
26	(561.3) Load Dispatch-Transmission Service and Scheduling	
27	(561.4) Scheduling, System Control and Dispatch Services	
28	(561.5) Reliability, Planning and Standards Development	
29	(561.6) Transmission Service Studies	
30	(561.7) Generation Interconnection Studies	
31	(561.8) Reliability, Planning and Standards Development Services	
32	(562) Station Expenses	
33	(562.1) Operation of Energy Storage Equipment	
34	(563) Overhead Line Expenses	
35	(564) Underground Line Expenses	
36	(565) Transmission of Electricity by Others	
37	(566) Miscellaneous Transmission Expenses	
38	(567) Rents	
39	(567.1) Operation Supplies and Expenses (Non-Major)	
40	TOTAL Transmission Operation Expenses (Lines 23 – 39)	

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC PRODUCTION, OTHER POWER SUPPLY, TRANSMISSION, **REGIONAL MARKET,** AND DISTRIBUTION EXPENSES(Continued)

Report Electric production, other power supply expenses, transmission, regional control and market operation, and distribution expenses through the reporting period.

Line No.	Account (a)	Year to Date Quarter
41	**Transmission Maintenance Expenses**	
42	(568) Maintenance Supervision and Engineering	
43	(569) Maintenance of Structures	
44	(569.1) Maintenance of Computer Hardware	
45	(569.2) Maintenance of Computer Software	
46	(569.3) Maintenance of Communication Equipment	
47	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	
48	(570) Maintenance of Station Equipment	
49	(570.1) Maintenance of Energy Storage Equipment	
50	(571) Maintenance Overhead Lines	
51	(572) Maintenance of Underground Lines	
52	(573) Maintenance of Miscellaneous Transmission Plant	
53	(574) Maintenance of Transmission Plant	
54	TOTAL Transmission Maintenance Expenses (Lines 42 – 53)	
55	Total Transmission Expenses (Lines 40 and 54)	
56	**3. REGIONAL MARKET EXPENSES**	
57	**Regional Market Operation Expenses**	
58	(575.1) Operation Supervision	
59	(575.2) Day-Ahead and Real-Time Market Facilitation	
60	(575.3) Transmission Rights Market Facilitation	
61	(575.4) Capacity Market Facilitation	
62	(575.5) Ancillary Services Market Facilitation	
63	(575.6) Market Monitoring and Compliance	
64	(575.7) Market Facilitation, Monitoring and Compliance Services	
65	Regional Market Operation Expenses (Lines 58–64)	
66	**Regional Market Maintenance Expenses**	
67	(576.1) Maintenance of Structures and Improvements	
68	(576.2) Maintenance of Computer Hardware	
69	(576.3) Maintenance of Computer Software	
70	(576.4) Maintenance of Communication Equipment	
71	(576.5) Maintenance of Miscellaneous Market Operation Plant	
72	Regional Market Maintenance Expenses (Lines 67-71)	
73	TOTAL Regional Control and Market Operation Expenses (Lines 65 and 72)	
74	**4. DISTRIBUTION EXPENSES**	
75	Distribution Operation Expenses (580-589)	
76	Distribution Maintenance Expenses (590-598)	
77	Total Distribution Expenses (Lines 75 and 76)	
78	TOTAL (Lines 20, 55, 73, and 77)	

Name of Respondent	This Report Is: (1) An Original (2) A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of Year/Qtr

PURCHASED POWER (Accounts 555 and 555.1)
(Including Power Exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract
defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		
					Average Monthly NCP Demand Total (e)	Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
	Total						

Name of Respondent	This Report Is: (1) An Original (2) A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of Year/Qtr

PURCHASED POWER (Accounts 555 and 555.1) (Continued)
(Including Power Exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatt hours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (n) totals to the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Purchases for Energy Storage on Page 401, line 11. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+ l+m) of Settlement ($) (n)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, Account 555.1, Power Purchased for Storage Operations and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Purchases (Account 555.1)				
4	Net Sales (Account 447)				
5	Transmission Rights				
6	Ancillary Services				
7	Other Items (list separately)				
8					
9					
10					
11					
12					
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41					
42					
43					
44					
45	Total				

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ______

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		22	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use)		23	Sales to Ultimate Consumers (Including Interdepartmental Sales)	
3	Steam		24	Requirements Sales for Resale (See Instruction 4, Page 311)	
4	Nuclear		25	Non-Requirements Sales for Resale (See Instruction 4, Page 311)	
5	Hydro-Conventional		26	Energy Furnished Without Charge	
6	Hydro=Pumped Storage		27	Energy Used by Company (Electric Department Only, Excluding Station Use)	
7	Other		28	Total Energy Losses	
8	Less Energy for Pumping		29	Total Energy Stored	
9	Net Generation (Enter Total of Lines 3 through 8)		30	TOTAL (Enter Total of Lines 23 Through 29) MUST EQUAL LINE 21 UNDER SOURCES	
10	Purchases (other than for Energy Storage)				
11	Purchases for Energy Storage				
12	Power Exchanges				
13	Received				
14	Delivered				
15	Net Exchanges (Line 12 minus Line 13)				
16	Transmission for Others (Wheeling)				
17	Received				
18	Delivered				
19	Net Transmission for Others (Line 16 minus line 17)				
20	Net Transmission for Others (Losses)				
21	TOTAL (Enter Total of Lines 9, 10, 11, 15, 19 and 20)				

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 KW or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use – KWh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) – KWh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Power Plant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / line 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power Generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc. Pumped Storage Plant	
35	Production Exp Before Pumping Exp (line 24 thru line 34)	
36	Pumping Expenses	
37	Total Production Exp (total line 35 and line 36)	
38	Expenses per KWh of Generation (line 37/ line 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
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			3
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			5
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			39

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ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 KW or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
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26				
27				
28				
29				
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32				
33				
34				
35	TOTAL			

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ______

ENERGY STORAGE OPERATIONS (Large Plants) (Continued)

	MWHs delivered to the grid to support			MWHs Lost During Conversion, Storage and Discharge of Energy			MWHs Sold (k)	Revenues from Energy Storage Operations (l)
Line No.	Production (e)	Transmission (f)	Distribution (g)	Production (h)	Transmission (i)	Distribution (j)		
1								
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3								
4								
5								
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7								
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11								
12								
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Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ______

ENERGY STORAGE OPERATIONS (Large Plants) (Continued)

Line No.	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Project Costs included in (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
1				Account 101			
2				Account 103			
3				Account 106			
4				Account 107			
5				Other			
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30				Total			

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 KW.
2 In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
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15				
16				
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21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36	TOTAL			

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ENERGY STORAGE OPERATIONS (Small Plants)(Continued)

	Plant Operating Expenses				
Line No.	Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
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35					
36					
37					
38					

Information from LG Chem (Note “Operating Years” below):

2. Technical Offer

2.1 System Configuration

Category	Content
Nameplate Power	1.2MW
Nameplate Energy	1.5MWh
Total Energy Installed 1)	1.77MWh
Total No. of Battery Racks	16ea
Total No. of Battery Modules	272ea
No. of Battery Container (Optional)	1ea
Type of Container (Optional)	SIP 30ft
Voltage Range	714 – 999.6VDC
Operating Years	10 Years
Standard Warranty	3 Years

Application No.:	A.16-09-
Exhibit No.:	SCE-09, Vol. 03
Witnesses:	P. Joseph A. Varvis R. White

SOUTHERN CALIFORNIA EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

Results of Operations
Volume 03 – Depreciation Study

Before the

Public Utilities Commission of the State of California

Rosemead, California
September 1, 2016

SCE-09: Results of Operation
Volume 03 - Depreciation Study

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I.

INTRODUCTION

Depreciation is the means by which SCE's investors recover the costs of the fixed capital investments they have made to provide electric service to SCE's customers. Depreciation provides a mechanism for recovery of the original cost of the investment and the future cost to retire the investment over its useful life. In each GRC, SCE submits a depreciation study that presents analyses of service lives and retirement costs. In Volume 2 of SCE-09, SCE set forth its proposed depreciation expense accruals for 2018-2020. This Volume 3 of SCE-09 describes the depreciation study undertaken by SCE's in-house and outside experts.

In this rate case, unlike prior ones, SCE undertook an *actuarial* analysis to estimate life parameters for its transmission and distribution (T&D) assets. Actuarial analyses rely on aged data, not on the unaged plant records that SCE used in the past to derive its proposed depreciation expense. SCE's actuarial analysis revealed that for 18 of 20 T&D accounts, the forecast service life of many assets is the same or longer than what had been authorized in the past. When service lives are extended, depreciation expense will decrease, all other things being equal.

However, a large driver impacting depreciation expense is cost of removal. As assets age, the effect of inflation increases cost of removal. Indeed, depreciation is a major expense in large part because it includes an allocation of the original cost of fixed capital and its estimated future cost of removal. This future removal cost, called net salvage, is defined as gross salvage minus cost of removal. When cost of removal is higher than gross salvage, as is commonly experienced in the utility industry, the value is negative and results in an increase to total depreciation expense. When that increasing cost to remove is expressed as a percentage of the original cost—a computation known as the net salvage ratio, or NSR—it becomes more negative as SCE's infrastructure ages.

In the 2015 GRC, the Commission directed SCE to conduct a more detailed analysis of its cost of removal for at least five of SCE's largest plant accounts as measured by proposed depreciation expense. That rigorous analysis, known as a "per-unit" analysis, differs from the traditional way in which SCE forecasts net salvage. Section C of Chapter II describes these differences in detail, but the main point is that under a per-unit analysis, SCE divides each plant account into "sub-populations" of similar assets, determines the historical cost to remove each unit in the sub-populations, and then applies the per-unit cost to the quantities identified in the surviving plant balance. SCE uses the surviving plant balance (*i.e.*, the mix of assets on SCE's books *today*) as the "window" into what future costs of removal will be, given the projected timing of the assets' retirement. This work is detailed and rigorous, and meets the Commission's compliance directives described in Chapter II. A traditional cost of removal analysis, applied to the balance of accounts, takes a more aggregated approach and generally assumes that future removal costs and activity will mimic what SCE experienced in the past. Both are accepted methods of forecasting the cost of removal, but the per-unit analysis is more detailed and labor-intensive.

The study results confirmed that SCE's NSRs are increasingly negative. That fact is not surprising given SCE's recorded history and the many other drivers SCE discusses in Section D of Chapter II. In fact, applying the results of the study would result in an estimated increase in depreciation expense of $963 million. However, SCE is not requesting to recover that sum over this GRC cycle given the resulting impact it would have on customers' retail rates. Rather, for reasons described in Section B of Chapter II, SCE elects to moderate its proposal in service of a public policy principle on which the Commission has relied before in the depreciation context—"gradualism." The idea is to spread the increases in depreciation expense over time to mitigate the immediate rate impact on customers. Thus, for T&D accounts where SCE's depreciation study results in an increase greater than 25% of currently authorized NSRs, SCE proposes to cap the increase at 25%. The result of applying this cap is to reduce SCE's proposal to $71 million above currently authorized, $892 million less than what the study results justify, as shown in Figure I-1 below.

A. <u>Organization of Testimony</u>

This chapter summarizes SCE's depreciation proposal comparing the "full" (un-tempered) empirical study results with SCE's moderated proposal. Section D of this chapter shows average life and NSR values for all accounts.

Sections A through C of Chapter II address the Commission's four compliance directives from SCE's 2015 GRC, which required additional quantitative detail to support SCE's net salvage proposals.[1] Section D of the same chapter offers qualitative reasons for SCE's increasingly negative net salvage rates.

Chapter III sets forth the results of SCE's depreciation study, based on plant assets as of December 31, 2015, separated into: (1) a life and net salvage analysis of Transmission and Distribution (T&D) assets, undertaken by SCE's outside expert (Section A of Chapter III); and (2) a life and net

[1] The compliance directives are also addressed in Chapter III, Section A.3.

salvage analysis of Generation assets, plus General and Intangible (G&I) assets, undertaken by SCE's in-house expert (Section B of Chapter III).

B. SCE's Depreciation Proposals

As shown in Table I-1, SCE's total proposed depreciation expense resulting from the study's revised parameters (using the moderated approach) is approximately five percent higher than recorded 2015 depreciation expense using the 2015 GRC-authorized depreciation rates.

Table I-1[2]
Depreciation Expense Proposal

Line No.	Item	Depreciation Expense (Nominal $M)	% Change from 2015 Recorded (Line 1)
1.	Recorded 2015 Depreciation Expense at Authorized Depreciation Rates (from 2015 GRC)	$1,656	
2.	Change due to 2016-2018 Plant Growth at Authorized Depreciation Rates	$266	*16.1%*
3a.	Change due to proposed Depreciation Rates applied to Year-End 2015 Recorded Plant	*$71*	*4.3%*
3b.	Change due to Proposed Depreciation Rates applied to 2018 Forecast Plant	*$10*	*0.6%*
3.	Total Change due to Depreciation Study (Sum of 3a and 3b)	**$81**	***4.9%***
4.	Proposed Test Year 2018 Depreciation Expense (Sum of Lines 1,2, and 3)	$2,003	*21.0%*

SCE's depreciation rate proposals (Line 3a above) can be separated into major functional categories as shown in Figure I-1 below.

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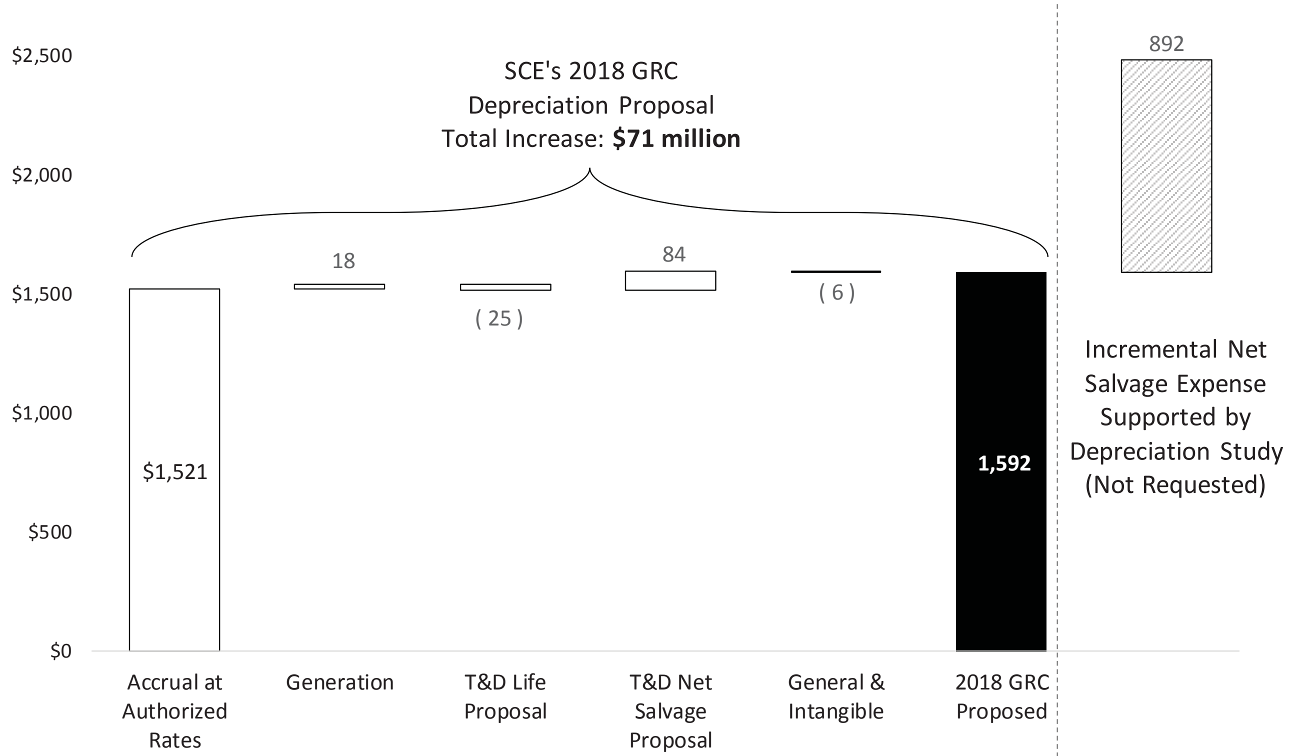
2 Refer to WP SCE-09 Vol. 03, Book A, pp. 1-20 (Depreciation Rate Proposals).

Figure I-1 [3]
Impact of Proposed Depreciation Rates by Class of Plant
(Based on Year-End 2015 CPUC-Jurisdictional Plant Balances, $M)



Note: The far left bar in the figure above shows a different number ($1,521M) from Table I-1 ($1,656) for two reasons: (1) It is calculated using only year-end 2015 plant balance instead of the full year 2015 recorded plant balances; and (2) it represents CPUC-jurisdictional depreciation expense only.

The increase in generation accruals is due primarily to shorter life proposals for hydro and solar facilities (See Section B of Chapter III). For T&D, SCE proposes to extend or retain average service lives for 18 of 20 accounts, and proposes more negative NSRs for 13 of 20 T&D accounts. The small change in General & Intangible accruals is the result of SCE's proposal to recover recorded reserve deficits.

As shown in Figure I-1 above, the results of SCE's net salvage analysis support a total increase in the annual accruals for net salvage of $976 million (assuming 2.72% inflation) consisting of SCE's requested $84 million plus an additional $892 million not requested in this rate case. Section C below

[3] Because this figure is based on CPUC-jurisdictional plant balances as of Year-End 2015, it does not include the impact of forecast plant additions from 2016-2018. The estimated impact of these forecast additions is shown in Line 2 of Table I-1 above.

discusses SCE's approach to moderating its T&D net salvage expense proposals to the requested $84 million.

C. Application of Gradualism Principle to SCE's Proposal

The results of the more rigorous per-unit net salvage analysis required as part of the Commission's directives from the 2015 GRC (see Chapter II), together with a forecast of the timing of retirements,[4] supports increasing SCE's annual accruals for T&D net salvage by $976 million above currently authorized levels. This depreciation proposal "as is" would translate into a large revenue requirement increase if the Commission were to adopt it. Given the magnitude of the impact this proposal would have on retail rates, SCE requests only $84 million for T&D net salvage accruals.

SCE chooses to "temper" its depreciation request in light of the Commission's recognition that while a utility could substantiate large depreciation expense requests through "empirical analysis of cost trends,"[5] more moderated rates may be in the public interest for reasons unrelated to empirical analyses. The Commission discussed this principle—known as "gradualism"—relatively recently in its Decision Authorizing Pacific Gas and Electric Company's (PG&E's) General Rate Case Revenue Requirement for 2014-2016, D.14-08-032, where it approved increased negative net salvage rates relative to PG&E's then-current rates "but at a reduced level relative to PG&E's forecasts to mitigate ratepayer impacts and to reflect the principle of gradualism."[6]

Specifically, the Commission concluded that for all asset accounts in which net salvage amounts were contested, it would adopt no more than 25% of the estimated net increase from current rates that would otherwise result from applying PG&E's net negative salvage rates (*e.g.*, if the previously approved NSR was -50% and PG&E requested -100%, the Commission adopted an NSR no more negative than -62.5%). The Commission concluded that 25% of the difference between then-current rates and proposed rates "gives some credence to the empirical methods used by PG&E while declining

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[4] To estimate the timing of retirements, SCE used the average retirement life and dispersion curves determined through its actuarial analyses, and then applied a 2.72% capital escalation assumption to determine forecast net salvage. For an explanation about the basis of the inflation assumption, refer to WP SCE-09 Vol. 03, Book A, p. 24 (Capital Escalation).

[5] D.14-08-032, p. 596.

[6] *Id.*, p. 11.

to pass along the full amount of PG&E's forecasted increase in negative salvage rates to current ratepayers."[7]

SCE's gradualism proposal in this proceeding uses a different formula than the one the Commission applied in PG&E's 2014 GRC Decision because SCE proposes to cap increases at 25% more than currently authorized NSRs rather than proposing an increase equal to 25% of the difference between proposed and authorized NSRs.[8] See Table I-2, below, for a summary of SCE's capping proposal (which was applied only to the accounts with gray highlights given that the study results would have increased the NSRs by more than 25% from authorized rates).

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[7] *Id.*, p. 602. In SCE's 2015 GRC, the Commission relied on its rationale from the PG&E case, stating that "[c]onsistent with the logic of gradualism that we applied to PG&E," it adopted a negative net salvage rate for Account 364 of -210% instead of the -225% that SCE had requested. D.15-11-021, p. 421. Similarly, for Account 369, SCE proposed an increase from -85% to -125%. "Consistent with gradualism," and for other reasons, the Commission adopted an increase to -100%. *Id.*, p. 425. In SCE's 2009 GRC, the Commission did not refer to "gradualism" as a doctrine but nonetheless tempered SCE's otherwise reasonable removal cost estimates "because of economic difficulties facing ratepayers." D.14-08-032, p. 599 (citing D.09-03-025, pp. 179-180).

[8] SCE's proposal, using the same calculation method as the Commission applied in the 2014 PG&E Decision, is equal to roughly 10% of the difference between currently authorized NSRs T&D accounts and what SCE's study results would justify.

Table I-2
SCE's Proposed Net Salvage Ratios for T&D Accounts

FERC Acct	Description	2015 GRC Authorized	Study Results	25% Above Authorized	SCE's NSR Proposals
A	B	C	D	E=C*1.25	G=Lesser of D or E
Transmission Plant					
352	Structures and Improvements	35%	35%	44%	35%
353	Station Equipment	15%	10%	19%	10%
354*	Towers and Fixtures	60%	185%	75%	75%
355*	Poles and Fixtures	72%	499%	90%	90%
356*	Overhead Conductors and Devices	80%	210%	100%	100%
357	Underground Conduit	0%	0%	0%	0%
358	Underground Conductor and Devices	15%	25%	19%	19%
359	Roads and Trails	0%	0%	0%	0%
Distribution Plant					
361	Structures and Improvements	25%	30%	31%	30%
362	Station Equipment	25%	50%	31%	31%
364*	Poles, Towers and Fixtures	210%	488%	263%	263%
365*	Overhead Conductors and Devices	115%	538%	144%	144%
366*	Underground Conduit	30%	401%	38%	38%
367*	Underground Conductor and Devices	60%	261%	75%	75%
368*	Line Transformers	20%	47%	25%	25%
369*	Services	100%	387%	125%	125%
370	Meters	5%	0%	6%	0%
373	Streetlights	30%	100%	38%	38%

* *Used a per-unit analysis to arrive at proposed net salvage rates*

The moderated NSRs, taken together with the balance of SCE's depreciation proposal, result in a total depreciation request that is less than 5 percent above what the Commission authorized for SCE in the 2015 GRC Decision.

SCE has weighed the balance between setting rates in this GRC based on cost-of-service principles, on the one hand, and being mindful of customer rate impacts, on the other. SCE also acknowledges errors inherent in any forecast of lives and removal costs of long-lived assets given the many variables that will eventually bear on the final costs. SCE recognizes the Commission's statement that one must "be cautious in making large changes in estimates of service lives and net salvage for property that will be in service for many decades, as future experience may show the current estimates to be incorrect."[9] Indeed, the premise of SCE's per-unit analysis is that one can take the per-unit historical

[9] D.14-08-032, p. 598.

cost to remove assets, and apply that per-unit cost to the *quantities* of assets in the surviving plant balance to obtain a reasonable forecast of the cost to remove the assets given projections about the timing of the assets' retirements. A key assumption in this analysis is the per-unit cost to retire each asset. While the proposals presented in SCE's depreciation study substantiate sound estimates of the future costs to retire, SCE does not overlook that future rate cases will provide updates to SCE's recorded experience that will further refine the expectations of future net salvage. That is, in future rate cases, SCE will have the ability to take its then-surviving plant balances to even better refine its projections about the future in light of then-available conclusions about historical costs-per-unit. By moderating SCE's depreciation expense, the Commission will make progress towards SCE's current estimate of forecast net salvage while permitting the Company in future rate cases to rely on additional data to refine its forecasts.

D. Summary Tables

Table I-3, Table I-4, and Table I-5 below summarize the life and net salvage parameters resulting from the analyses described in the chapters below.

Table I-3[10]
Summary of SCE's Request for Depreciation Parameters - Transmission and Distribution

FERC Account	Description	Net Salvage Rates Auth.	Net Salvage Rates Prop.	Net Salvage Rates Change	Curves and Lives Auth.	Curves and Lives Prop.	Curves and Lives Change	Depreciation Rates Auth.	Depreciation Rates Prop.	Depreciation Rates Change
A	B	C	D	E=D-C	F	G	H=G-F	I	J	K=J-I
Transmission										
352	Structures and Improvements	-35%	-35%		S 3.0 55	L 1.0 55		2.53%	2.40%	-0.13%
353	Station Equipment	-15%	-10%	5%	R 0.5 45	L 0.5 40	-5	2.66%	2.84%	0.18%
354	Towers and Fixtures	-60%	-75%	-15%	R 5.0 65	R 5.0 65		2.30%	2.73%	0.43%
355	Poles and Fixtures	-72%	-90%	-18%	R 0.5 50	SC 65	15	3.43%	2.84%	-0.59%
356	Overhead Conductors & Devices	-80%	-100%	-20%	R 3.0 61	R 3.0 61		2.63%	3.24%	0.61%
357	Underground Conduit	0%	0%		R 3.0 55	R 3.0 55		1.73%	1.73%	0.00%
358	Underground Conductors & Devices	-15%	-19%	-4%	R 2.5 40	S 1.0 45	5	2.65%	2.41%	-0.24%
359	Roads and Trails	0%	0%		SQ 60	R 5.0 60		1.52%	1.65%	0.13%
Distribution										
361	Structures and Improvements	-25%	-30%	-5%	R 2.5 42	L 0.5 50	8	3.04%	2.39%	-0.65%
362	Station Equipment	-25%	-31%	-6%	R 1.5 45	L 0.5 65	20	3.13%	2.01%	-1.12%
364	Poles, Towers and Fixtures	-210%	-263%	-53%	L 0.5 47	R 1.0 55	8	7.04%	7.09%	0.05%
365	Overhead Conductors & Devices	-115%	-144%	-29%	R 0.5 45	R 0.5 55	10	4.87%	4.49%	-0.38%
366	Underground Conduit	-30%	-38%	-8%	R 3.0 59	R 3.0 59		2.22%	2.27%	0.05%
367	Underground Conductors & Devices	-60%	-75%	-15%	R 0.5 45	R 1.5 43	-2	2.98%	3.94%	0.96%
368	Line Transformers	-20%	-25%	-5%	R 1.0 33	S 1.5 33		3.93%	4.57%	0.64%
369	Services	-100%	-125%	-25%	R 1.5 45	R 1.5 45		4.34%	5.04%	0.70%
370	Meters	-5%	0%	5%	R 3.0 20	R 3.0 20		5.30%	5.61%	0.31%
373	Street Lighting & Signal Systems	-30%	-38%	-8%	L 0.5 40	L 1.0 48	8	3.10%	3.00%	-0.10%
General Buildings										
390	Structures & Improvements	-10%	-10%	0%	R 3.0 38	R 0.5 45	7	2.74%	2.08%	-0.66%

Used a Per-Unit Analysis to analyze Net Salvage

Moderated as discussed in Chapter 1, Section C

Proposed Retention of Currently Authorized Lives

[10] Refer to WP SCE-09 Vol. 03, Book A, pp. 5-20 (Rate Determination Schedule).

Table I-4[11]
Summary of SCE's Request for Book Depreciation
Generation Plant

Generation Facility	Life Spans		Net Salvage	
	Auth.	Prop.	Auth.	Prop.
A	B	C	D	E
Nuclear Production - Palo Verde	30.5 yrs.	28.0 yrs.	Covered under NDCTP	
Hydro Production	26.0 yrs.	19.9 yrs.	$79.3 M	$95.3 M
Other Production				
Pebbly Beach	45 yrs.	25 yrs.	$6.6 M	-
Mountainview	35 yrs.	35 yrs.	$16.3 M	$18.5 M
Peakers	35 yrs.	35 yrs.	$12.1 M	$15.1 M
Solar Photovoltaic	25 yrs.	20 yrs.	$81.9 M	$80.9 M
Fuel Cells	10 yrs.	10 yrs.	-	-
Energy Storage	N/A	10 yrs.	N/A	-

Table I-5[12]
Summary of SCE's Request for Book Depreciation
General and Intangible Plant

FERC Account	Description	Lives		Depreciation Rates	
		Auth.	Prop.	Auth.	Prop.
A	B	C	D	E	F
General Plant					
389.2	Easements	60	60	1.67%	1.67%
391.1	Office Furniture	20	20	5.00%	5.00%
391.2	Personal Computers	5	5	20.00%	20.00%
391.3	Mainframe Computers	5	5	20.00%	20.00%
391.4	DDSMS-Security Monitoring System	Various	Various	12.90%	9.84%
391.5	Office Equipment	5	5	20.00%	20.00%
391.6	Duplicating Equipment	5	5	20.00%	20.00%
391.7	PC Software	5	5	20.00%	20.00%
393	Stores Equipment	20	20	5.00%	5.00%
394	Tools & Work Equipment	10	10	10.00%	10.00%
395	Laboratory Equipment	15	15	6.67%	6.67%
397	Telecommunication Equipment	Various	Various	9.77%	11.65%
398	Misc. Power Plant Equipment	20	20	5.00%	5.00%
Intangible Plant					
302.020	Hydro Relicensing	Various	Various	2.52%	2.47%
303.640	Radio Frequency	40	40	2.50%	2.50%
302.050	Miscellaneous Intangibles	20	20	5.00%	5.00%
303.105	Capitalized Software - 5 year	5	5	20.00%	20.00%
303.707	Capitalized Software - 7 year	7	7	14.29%	14.29%
303.210	Capitalized Software - 10 year	10	10	10.00%	10.00%
303.315	Capitalized Software - 15 year	15	15	6.67%	6.67%

[11] *Id.*, pp. 5-7.
[12] *Id.,* pp. 9-12.

II.

COMMISSION DIRECTIVES FROM SCE'S 2015 GRC DECISION

In the 2015 GRC Decision, the Commission gave four directives for SCE's net salvage proposals in this 2018 GRC proceeding. Most of the remainder of this chapter explains SCE's approach to meeting each of the directives. Section D addresses SCE's experience with increasingly negative net salvage rates (this testimony refers to "higher" net salvage rates, for simplicity's sake) and demonstrates how the advancing age of SCE's infrastructure and the increasing urbanization within its service territory has contributed to more negative NSRs.

A. The Four Directives Established in the 2015 GRC Decision

Ordering Paragraph 9 of the 2015 GRC Decision required SCE to "provide considerably more detail in support of its net salvage proposals for at least five of the largest accounts, as measured by proposed annual depreciation expense" including at least the following:[13]

The First Directive

> "A quantitative discussion of historical and anticipated future Cost of Removal (COR) on a per unit basis for the large (greater than 15% as measured by portion of plant balance) asset classes in the account. This discussion should identify and explain the key factors in changing or maintaining the per-unit COR."

The Second Directive

> "A quantitative discussion of historical and anticipated future retirement mix (i.e., retirements among different asset classes), identifying and explaining the key factors in changing or maintaining this mix."

The Third Directive

> "A quantitative discussion of the life of assets and original cost of assets being retired, in relation to the COR, on both a historical and anticipated future basis. This discussion should be integrated with and/or cross-reference the proposal for life characteristics."

The Fourth Directive

> "An account-specific discussion of the process for allocating costs to COR."[14]

The per-unit analysis required by the Commission involves substantially more work than a "traditional" net salvage analysis that is typically performed by the industry (as described in Standard Practice U-4).[15]

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[13] D.15-11-021, Ordering Paragraph 9, p. 554.
[14] *Id*., pp. 554-555.
[15] For the purpose of this testimony, the term "traditional approach" will be used to describe Standard U-4.

Table II-6, below, summarizes the differences at a high level, and Sections B and C of this chapter goes into more detail.

Table II-6
Summary of Difference Between Per-Unit Analysis and Traditional Approach

	Compliance Directive from 2015 GRC	Per-Unit Analysis (Required by 2015 GRC Decision)	Traditional Approach (As Established in Standard Practice U-4)
1.	**Perform a per-unit COR analysis**	Separate account into sub-populations (*e.g*., account 365 conductor vs. account 365 switches) and calculate a per-unit COR. Math: Historical cost to retire assets divided by *quantities* of property units being retired within each subpopulation.	Calculate NSR at the account level of detail (e.g., account 365). Math: Historical cost to retire assets divided by *original cost* of assets retiring.
2.	**Discuss Whether Retirement Mix Will Change Or Stay The Same**	Apply the per-unit cost estimate results to surviving plant balance assuming that the future retirement mix will be consistent with the current plant balance.	Assumes that the future retirement mix will mimic SCE's recorded experience.
3.	**Integrate Salvage Analysis with Life Analysis**	Utilize original cost of current plant-in-service and results of the life analysis to estimate timing and cost of future retirements.	Assume that the future average age of retirements, and the inflation embedded in the cost of removal, will both mimic recorded activity.
4.	**Discuss COR Allocation**	Provide account-specific discussion for the process for assigning costs to cost of removal (versus install).	

B. <u>SCE's Approach to Addressing the Compliance Directives from the 2015 GRC Decision</u>

To comply with the directives from the 2015 GRC Decision, SCE performed a per-unit analysis for "at least five of the largest accounts, as measured by [the] proposed annual depreciation expense." As shown in Table II-7, below, the five largest accounts under that definition are distribution accounts 364, 365, 367, 368, and 369.[16]

SCE performed a per-unit analysis on nine T&D accounts, which comprise 85% of the total COR expense proposed. Apart from the five largest accounts, SCE performed a per-unit analysis on another distribution line account, Account 366, which is the only remaining account in the series 364-369 (covering distribution line circuits). In addition, SCE performed a per-unit analysis for Account 354 (Transmission Towers) because a traditional analysis produced anomalous estimates of future net salvage rates (upwards of -800%) resulting from the removal of very old towers with a high cost to retire. SCE also selected accounts 355, 356, and 366 (Transmission Poles, Transmission Overhead

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[16] The same five T&D accounts represented the top five accounts (measured by proposed depreciation expense) in the 2015 GRC.

Conductor, and Distribution Underground Conduit respectively) given their similarity to corresponding distribution account assets for which SCE conducted a per-unit analysis.

The Commission's directives from the 2015 GRC Decision stand alone. However, in the course of complying with those directives, SCE is indirectly addressing related directives from SCE's 2012 GRC Decision (D.12-11-051, pp. 683-686). In the 2012 GRC decision, the Commission asked SCE to: (1) provide more information about its cost of removal estimates; and (2) to "review its allocation practices to be sure that all installation-related costs are booked to Plant-in-Service," instead of to cost of removal.[17] Both decisions request additional information substantiating removal costs and reviewing SCE's cost allocation. The primary distinction is that the 2015 GRC Decision required SCE to analyze its largest accounts by the proposed depreciation expense, whereas the 2012 GRC Decision instead required that SCE select its largest accounts using industry comparisons.

[17] D.12-11-051, p. 683.

Table II-7
T&D Accounts Ranked by Proposed Annual Depreciation Expense
(Based on CPUC-Jurisdictional Depreciation Expense ($M))

FERC Account	Description	Proposed Depr. Exp.	Rank
Transmission Plant			
352	Structures and Improvements	5,101	*15*
353	Station Equipment	62,978	*6*
354	Towers and Fixtures	2,603	*16*
355	Poles and Fixtures	19,820	*11*
356	Overhead Conductors & Devices	7,856	*13*
357	Underground Conduit	1,053	*17*
358	Underground Conductors & Devices	6,160	*14*
359	Roads and Trails	114	*18*
Distribution Plant			
361	Structures and Improvements	13,783	*12*
362	Station Equipment	45,110	*8*
364	Poles, Towers and Fixtures	174,654	***2***
365	Overhead Conductors & Devices	64,341	***5***
366	Underground Conduit	44,209	*9*
367	Underground Conductors & Devices	218,724	***1***
368	Line Transformers	160,345	***3***
369	Services	65,591	***4***
370	Meters	50,205	*7*
373	Streetlights	26,163	*10*
Total		968,810	

Proposals based on results of Per-Unit Analysis ($758M or 78% of Total Expense)

1. The First Directive – Per Unit Net Salvage Analysis

The per-unit net salvage analysis segments each FERC plant account into large subpopulations (*i.e.*, dollar value of assets representing more than 15% of the total account balance).[18] To calculate the average per-unit cost to remove, SCE divided the net salvage dollars incurred by the quantity of units retired for each of the identified subpopulations. For example, Account 368—

[18] In the first compliance directive from the 2015 GRC Decision, the Commission referred to "large . . . asset classes in the account" as measured by 15% or more of the portion of plant balance. D.15-11-021, p. 398. SCE uses the term "subpopulation" to refer to those large asset classes within each FERC account.

Distribution Line Transformers—consists of three major subpopulations; overhead (OH) transformers, underground (UG) transformers, and fuseholders. For each subpopulation, SCE divided the net salvage incurred from 2009-2015[19] by the quantity of units retired, as shown in Figure II-3, below. This per-unit cost to remove each asset formed one part of the basis for forecasting SCE's expected future net salvage proposals presented in this GRC.

a) Traditional Approaches to Analyzing Historical and Future Net Salvage

Standard Practice U-4, Determination of Straight-Line Remaining Life Depreciation Accruals ("U-4," or "Standard Practice U-4"), "sets forth various factors influencing the determination of depreciation accruals and describes methods of calculating these accruals"[20] with the purpose of assisting "the Commission staff in determining proper depreciation expenses."[21] Although over 50 years old, Standard Practice U-4 represents conventional utility depreciation practices. The depreciation rates proposed in this study are consistent with the standard practices described in U-4. In addition, SCE conducted a more rigorous per-unit analysis for nine T&D accounts in response to the Commission's directives from the 2015 GRC.

To meet requirements set forth in U-4, SCE uses different approaches to estimate NSRs based on the plant's retirement characteristics and recorded experience. Broadly speaking, SCE's net salvage study analyzes mass property differently than life-span property and other non-mass plant accounts. Mass property accounts (*e.g.,* transmission and distribution plant accounts) are those that have a significant number of property units which are generally retired separately. Life-span property refers to accounts which are comprised of a few major units which individually are expected to retire at a single point in time (*e.g.*, generating plants).

Mass property plant accounts, such as T&D, can contain a significant number of components and generally experience large numbers of retirement transactions under a diverse number of retirement circumstances. The large number of retirement units and retirement occurrences for mass property generally necessitate an analysis of *aggregate* historical NSRs and per-unit costs. To accomplish this, Standard Practice U-4 describes how to estimate future net salvage rates using the

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19 This period contains detailed net salvage data by CPR, available in PowerPlan, SCE's capital system of record. Net salvage data prior to this period is maintained at the FERC prime account level only.

20 Standard Practice U-4 is available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M042/K177/42177433.PDF and includes methods to analyze net salvage.

21 *Id.*, p. 6.

experienced ratios of net salvage, gross salvage, and removal cost (in today's dollars) as a percent of the original installed costs (in older dollars) of retirements. The average net salvage rate by FERC account is then applied to the total plant balance to determine the estimated future net salvage amount, barring any adjustments. Understanding the inputs involved in the calculation and the calculation itself is important to interpreting the resulting NSRs. The calculations are as follows:

Figure II-2
Computing NSRs Under the Traditional Approach

$$\text{Net Salvage \%} = \text{Gross Salvage \%} - \text{Removal Cost \%}$$

$$\frac{\text{Net Salvage (\$)}}{\text{Retirements (\$)}} = \frac{\text{Gross Salvage (\$)}}{\text{Retirements (\$)}} - \frac{\text{Removal Cost (\$)}}{\text{Retirements (\$)}}$$

b) <u>Comparing the Differences Between Calculating Net Salvage Ratios Using a Traditional Analysis Versus Per-Unit Analysis</u>

The first and most important way that a per-unit analysis differs from the traditional analysis is that the NSRs are computed using the original cost of the *surviving* plant balance (*i.e.*, the current plant balance), as opposed to a traditional analysis' use of the original cost of the plant that has already *retired*. That is, a traditional net salvage analysis examines the *historical* NSRs as the principal factor used to estimate *future* NSRs. By contrast, the per-unit analysis takes historical per unit costs and applies them to surviving plant *quantities* to project future removal costs given projections (from the life analysis) of when assets are expected to retire. The traditional approach implicitly assumes that factors such as the age of retirements, changes in SCE's operating environment, levels of inflation and other factors will, in the future, be the same as they were in the past. By contrast, a per-unit analysis develops forward-looking estimates of net salvage by relying on recorded costs, surviving plant balances, and assumptions about the timing of future retirements.

An illustration of SCE's approach to the per-unit analysis computation is instructive, especially compared to the calculation in Figure II-2, above. First, the net salvage cost per-unit is calculated by summing seven years' worth of recorded history—in both dollars used to remove assets, and quantities of assets removed—to arrive at a per-unit net salvage value by sub-population:

Figure II-3
Calculation of Per-Unit Net Salvage Costs
(Recorded 2009-2015 values for Account 368 – Line Transformers)

$$\text{Per-Unit Net Salvage} = \frac{\text{Net Salvage (\$)}}{\text{Quantity Retired}}$$

		Overhead Transformer	Underground Transformer	Fuseholder	Others
Per-Unit Net Salvage	=	$79,500,742 / 141,838	$78,642,058 / 53,904	$44,409,667 / 275,472	$19,071,340 / 19,862
	=	$560.50	$1,458.93	$161.21	$960.19

Next, the per-unit cost derived above is applied to a forecast using anticipated rates of inflation, as opposed to inflation experienced in the past. A simplified (no-inflation) calculation of future net salvage is shown in Figure II-4, as it shows the per-unit net salvage from Figure II-3 multiplied by the year-end 2015 surviving quantities (the study date). The resulting value is equivalent to an estimate of the cost to remove all of the assets in Account 368 as of the study date.

Figure II-4 [22]
Calculation of Future Net Salvage Using a Per-Unit Methodology
(for Account 368 – Line Transformers; excluding future inflation)

Future Net Salvage = Per-Unit NS x Per-Unit Surviving Quantity

		Overhead Transformer		Underground Transformer		Fuseholder		Others
Future Net Salvage	=	$560.50 x 456,611	+	$1,458.93 x 259,299	+	$161.21 x 1,400,640	+	$960.19 x 62,788
$920,320,858	=	$255,932,428		$378,298,499		$225,801,375		$60,288,556

This forecast of future net salvage can be divided by the costs of assets currently serving customers (the denominator, or surviving plant balance) to arrive at an estimated future NSR. This no-inflation estimate of the future NSR is shown in Figure II-5 below.

[22] Refer to WP SCE-09 Vol. 03, Book A, pp. 21-24 (Per-Unit Calculations).

Figure II-5[23]

Derivation of Future Net Salvage Rate Under a Per-Unit Analysis

(for Account 368 – Line Transformers; excluding future inflation)

$$\text{Future Net Salvage Rate} = \frac{\text{Future Net Salvage}}{\text{Surviving Plant}}$$

$$\mathbf{\mathit{26.7\%}} = \frac{\$920{,}320{,}858}{\$3{,}450{,}870{,}284}$$

To summarize, a per-unit analysis estimates future net salvage by: 1) establishing a per-unit cost to retire each asset, 2) applying results of the life analysis to estimate when these costs will be incurred, and 3) dividing this forecast net salvage by the surviving plant balance. See Figure II-6 below for a simplified comparison of the differences.

Figure II-6

Simplified Comparison of Traditional Analysis vs. Per-Unit Analysis

Traditional Analysis

$$\textbf{Future Net Salvage Rate} = \frac{\text{Net Salvage Incurred}}{\textit{Cost}\ \text{Retired}}$$

Per-Unit Analysis

$$\text{Per-Unit Net Salvage} = \frac{\text{Net Salvage Incurred}}{\textit{Quantity}\ \text{Retired}}$$

$$\text{Future Net Salvage} = \text{Per-Unit Net Salvage} \times \text{Surviving Quantity}^{1}$$

$$\textbf{Future Net Salvage Rate} = \frac{\text{Future Net Salvage}}{\text{Surviving Plant}^{2}}$$

1. Multiplying by surviving quantity produces forward-looking estimates of net salvage (in more complex examples, the timing of removal and level of inflation will change the per unit net salvage value).

2. Using the surviving plant balance is representative of the future retirement mix.

2. The Second Directive – Retirement Mix

The second directive, requiring a discussion of the historical and future retirement mix, has been addressed by separating the original directive into two sub-directives (1) an analysis and

[23] *Id*.

discussion of the historical retirements, and (2) a discussion of the expected future retirement mix. The per-unit analysis described above complies with the first sub-directive because it requires review of the historical mix of retirements to determine an average per-unit cost to retire. To address the second sub-directive, SCE assumes that the future retirement mix will be consistent with the asset mix in the surviving plant balance as of year-end 2015. (In future rate cases, when the retirement mix changes, the forecast NSR will change accordingly.)

Analyzing the account by subpopulation achieves a more detailed "weighting" than looking at the account-based retirement mix in the aggregate. That is, the traditional approach focuses solely on the backward-looking ratios, which are used to estimate *future* net salvage. The blunt assumption underlying this approach is that the mixture of asset retirements in the past is representative of what one could expect in the future without regard to the composition of the then-current plant balance. Under the per-unit approach, by contrast, one focus is on the *surviving* plant balance, which offers a "snapshot" in real time that forms the basis for estimating the future mix of retirements. In determining its proposed depreciation expense, SCE did not identify or rely on factors that would cause it to modify the future retirement mix relative to the mix that currently exists in its plant accounts. Should factors in the future modify the retirement mix, the surviving plant balances examined at the relevant time will integrate and reflect those changes.

3. **The Third Directive – The Age of Retirements and Integration of Salvage and Life Analyses**

The third directive requires SCE to provide a quantitative discussion of the life of assets and original cost of assets being retired in relation to the cost of removal. This directive has been addressed by separating the original directive into two sub-directives requiring (1) a discussion of the age of retirements *experienced* and (2) a forecast of the *future* age of retirements given the results of the life analysis. The Commission intended this directive to "integrate" the life analysis with the COR analysis: "This [COR] discussion should be integrated with and/or cross-reference the proposal for life characteristics."[24] The only way to properly integrate both prongs of the analysis is to factor in the impact of the *passage of time*, or inflation, on the per-unit costs. To address this directive, SCE has provided the average age and original cost of assets retired, together with a forecast of future retirements

[24] D.15-11-021, p. 398 (see also Ordering Paragraph 9.i., pp. 554-555).

using the results of the life analysis. SCE's forecasts are derived by integrating the historical (per-unit) cost to remove each asset with the forecast retirements from the life analysis.

4. <u>The Fourth Directive – Process for Assigning Costs</u>

In compliance with the fourth directive from the 2015 GRC Decision—requiring SCE to provide an "account-specific discussion of the process for allocating costs to COR" for at least five of the largest accounts[25] — Section C below describes in detail SCE's process for allocating a portion of total work order costs to cost of removal.

C. <u>Process for Assigning Costs to Installation and Removal (The Fourth Directive)</u>

The 2015 GRC Decision requested an "account-specific" discussion of the process for allocating costs to removal. For every capital project SCE undertakes, one or more work orders is created and populated with a Unit Estimate (UE) in PowerPlan, which is SCE's fixed asset accounting software system. UEs are comprised of *property* descriptions, otherwise known as continuous property records (CPRs), and *activity* descriptions. An example of a CPR is 364.330 for a distribution wood pole the "364" refers to FERC plant account 364 Distribution Poles, and the ".330" suffix refers to an SCE-specific retirement unit, in this case, a solely-owned wood pole.

The activity description of a UE is used to denote whether the activity undertaken within each work order involves: <u>I</u>nstallation of a new asset, <u>R</u>emoval of an existing asset, or related <u>E</u>xpense (I/R/E).[26] For each project, SCE personnel will populate a UE with the CPR and activity types that are specific to the project that they are estimating. (Note that capital material costs are assigned to <u>I</u>nstall, whereas, labor costs are assigned to I/R/E.)

UEs originate from two different "categories" of capital projects, each of which broadly uses a different cost assignment methodology. The first category is relevant to bulk-power transmission, substation, and generation-related projects, which combined account for approximately 15% of SCE's total 2016-2020 forecast cost of removal in this rate case. In general, the assets in this category are booked to all plant accounts other than Accounts 364-373, and the process for allocating costs is described in subsection II.C.1, "Project-Specific Estimating" below.

The second category is relevant to distribution and sub-transmission line assets (*e.g.*, poles, conductors, streetlights, etc.), which together account for the majority (approximately 85%) of SCE's

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[25] *Id.*

[26] For this cost assignment description, the "expense" category is considered a non-capitalized activity but is included here for completeness.

total 2016-2020 forecast COR in this rate case. At a high level, the assets in this second category (sometimes referred to as "mass plant" assets) are booked to Accounts 364 to 373, and the process for assigning costs is described in subsection II.C.2., "Design Manager (DM) Estimating" below.

1. Project-Specific Estimating (Bulk-Power Transmission, Substation, and Generation/Other)

For project-specific estimating, SCE personnel create a detailed cost estimate for each of the activities required at the outset of each job. The cost estimate reflects the total estimated costs of *installation* separate from the total estimated costs of *removal*.

a) Bulk Power Transmission and Substation (Accounts 350-359 and 362)

For bulk power transmission and substation estimates,[27] engineers and technical experts use the Scope and Cost Management Tool (SCMT) to document, track, and communicate the scope for each project. Cost estimators then complete the costs for each project identifying and separating the installation, removal and expense activities. They assign CPR accounts that serve as the basis for creating the UEs that will ultimately be uploaded into the PowerPlan system.

For example, a capital project to replace a bulk power (*e.g.*, 500/220 kV) transformer begins when the estimator develops a specific cost estimate by itemizing the scope of major activities (*e.g.*, removing the old transformer, trench cover, power/control cable, conduits, etc. and then installing the new equipment).[28] The installation and removal activities are separately identified by hours required to install and/or remove the particular assets. In other words, there is a specific estimate of the labor, equipment, and associated overheads required to remove assets, and it is not a template-based "allocation" of *total* hours required for the job. The work is also broken out by the specific classification of employee who will be performing the task and also whether or not SCE crews or contract crews will be performing the work. The details of this estimate are compiled and used to create the UE in PowerPlan that will assign the ultimate costs recorded as "installation" costs versus "removal" costs.

b) Generation and Other (Accounts 301-348, and 390-398) [29]

Generation, Information Technology, and Operational Services also use project-specific estimating. That is, a detailed scope of work is set by engineers and other technical experts. The

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[27] Examples of accounts with related assets are Accounts 350 to 359 and 362.

[28] Refer to WP SCE-09 Vol. 03, Book A, pp. 25-41 (Project-Specific Estimating) for an example of a project-specific estimate.

[29] Examples of some of these accounts are: Accounts 301 to 348 and 390 to 398.

scope of work is separated into installation and removal activities and becomes the foundation for building the UEs that are put in the PowerPlan System.

2. Design Manager (DM) Estimating (Distribution/Sub-Transmission Assets)

For the large majority of capital assets, such as distribution and some sub-transmission line assets (*e.g.*, poles, conductors, streetlights, etc.), it is impractical for SCE to use project-specific estimating every time a new capital project is undertaken. That is because in any given year, SCE will install and replace thousands of these units of property. For example, in 2015 alone, SCE replaced over 40,000 wood poles, 25,000 transformers, and 3,000 miles of conductor.[30]

To manage the high volume of work, SCE uses a template-based estimating approach to assign a capital project's total costs to Installation, Removal, and Related Expense (I/R/E). Since 2010, SCE's planners have been using Design Manager to estimate labor hours, schedule work, and price distribution and sub-transmission projects. The DM estimating approach is commonly used for emergency work, planned/routine work, and customer-driven projects including relocations, overhead/underground conversions, new service connections and meter installations. A subset of data from DM is sent to PowerPlan, and that is where SCE's allocation methodology is applied for fixed asset accounting purposes, as explained in more detail below.

a) Building a Project Estimate in DM Using Compatible Units (CUs)

A planner tasked with initiating a project (*e.g.*, a pole replacement) will open a work order and, based on the project scope (including site visits, where applicable), begin identifying Compatible Units (CUs) required to complete the job. CUs are building blocks of material and labor used to develop the distribution design and work order cost estimates. They eliminate the need for planners to manually identify and select every material component for frequently installed equipment and structures on SCE's electrical system. CUs identify the quantity and type of property needed for a project (*e.g.*, wood poles, transformers, conductors, etc.) and associated estimates of labor hours and costs. DM contains legend codes to indicate the type of activity to be performed for each asset (*i.e.*, installation vs. removal). DM incorporates the use of over 4,500 distribution CUs, to help planners build cost estimates and schedule work depending on the requirements of the job.

[30] Refer to WP SCE-09 Vol. 03, Book D, pp. 2-40 (Per-Unit Net Salvage Analysis). Estimates are taken from per-unit analysis quantity.

b) Cost Allocation in PowerPlan

For purposes of fixed asset accounting, the CUs and legend codes from DM work orders are migrated to PowerPlan. CUs are paired with—and converted to—one of over 100 CPR accounts.[31] At this point, the CPR account consists only of quantities and types of property to be installed and, if applicable, quantities and types of property to be removed. The estimated costs and labor hours from DM are not carried over to PowerPlan. For fixed asset accounting purposes, SCE uses a "Standard Rates Table"[32] to allocate installation and removal costs relative to total project costs of individual work orders. The Standard Rates Table is also used to allocate costs among the appropriate FERC accounts.

Each CU relates to a specific, individual piece of property. For example, different CUs are used to reflect the various height, class, material, and treatment status[33] of poles. Likewise, different CUs are used to reflect the various size, voltage and even manufacturer of transformers. The number of CUs that planners use to build a UE is many times greater than the number of CPRs to which the CUs are paired in PowerPlan. The Standard Rates Table allocation is therefore performed at an aggregated level that accounts for the various types of property the CPRs encompass. The table has been in continuous use since approximately the 1970s and it sets forth allocation factors that have been studied but that have not been materially modified over the years. However, in Chapter II.C.2.c., SCE describes three studies validating that the Standard Rates Table's general allocations continue to be reasonable, if not more conservative in assigning costs to removal versus installation.

An example of how the Standard Rates Table works in PowerPlan is illustrated in the three tables below, Table II-8, Table II-9, and Table II-10. Assume that a project to replace a wood pole also requires replacing an attached streetlight fixture. The table below lists the CPRs and the associated allocation factors by activity:[34]

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[31] A CPR account is defined as the combination of a FERC plant account and a retirement unit subaccount.
[32] In prior rate cases, this "Standard Rates Table" has sometimes been referred to as "Table 34."
[33] Treatment processes vary and are used to minimize pole decay (*e.g.*, through-boring, treatments, etc.).
[34] Note that the numbers are neither dollars nor hours; they are allocation factors from the Standard Rates Table. Refer to WP SCE-09 Vol. 03, Book A, pp. 47-51 (Standard Rates Table).

Table II-8
Standard Rates Table Values

CPR Account	Description	Standard Rates Table Values				
		Install		Removal		Total
364.330	Distribution Wood Pole	1,286	+	600	=	1,886
		+		+		
373.390	Streetlight fixture	105	+	74	=	179
		=		=		
	Total	1,391	+	674	=	**2,065**

The Standard Rates Table values are not important as absolute values; they are only meaningful in relation to each other. In the example above, the value assigned to removing the pole (600) is—appropriately—much larger than the value assigned to removing the fixture (74).

Table II-9 below converts the values in the rows and columns above to percentages of the total. Comparing the values across columns shows the allocation between install and removal. Comparing the values between rows shows the allocation between CPR accounts.

Table II-9
Percent of Sum of Standard Rates

CPR Account	Description	Percent of Sum of Standard Rates Values				
		Install		Removal		Total
364.330	Distribution Wood Pole	*62%*	+	*29%*	=	*91%*
		+		+		
373.390	Streetlight fixture	*5%*	+	*4%*	=	*9%*
		=		=		
	Total	*67%*	+	*33%*	=	***100%***

Allocation between CPR Accounts

Allocation between Install and Removal for replacement project

For fixed asset accounting purposes, the percentages from the table above are applied to the allocable dollars[35] in the project's work order, as shown in Table II-10 below.

[35] Material costs are generally allocated to installation, not removal.

Table II-10
Application of Standard Rates to $1,000 of Labor

CPR Account	Description	Application of Standard Rates to $1,000 of Labor				
		Install		Removal		Total
364.330	Distribution Wood Pole	$623	+	$290	=	$913
		+		+		
373.390	Streetlight fixture	$51	+	$36	=	$87
		=		=		
	Total	$674	+	$326	=	**$1,000**

As illustrated in Table II-8, Table II-9, and Table II-10 above, while the Standard Rates Table uses a template approach to setting allocation factors, the resulting cost assignment for each project is "customized" in several ways. First, by virtue of the planner's initial designation of CU legend codes, the *activity* for each CPR is appropriately designated as "installation" versus "removal," and these splits are specific to each project depending on the properties and quantities that are installed or removed. Second, the *quantities* of property estimated by planners are drawn into PowerPlan and trued up by the end of every project to reflect what was actually removed and installed. Third, and most importantly, as units of property and quantities change with each work order, the matrix of cost assignment becomes more complex and reflective of the work performed in that project. For example, if another CPR account were added to the illustration above, the resulting allocations would be modified to reflect the weight of each CPR account relative to the total.

3. <u>Substantiating SCE's Standard Rates Table Allocation Factors</u>

SCE has conducted three studies substantiating the results of the Standard Rates Table's installation and removal allocation factors—in 2004, 2006, and 2016. The results of these three studies are summarized in Table II-11, which shows the CORs as a percentage of total costs under the Standard Rates Table compared to the COR percentages from the 2004, 2006 and 2016 Studies. The table demonstrates that SCE's allocation practice continues to be reasonable and appropriate. In fact, the Standard Rates Table COR allocations (on which the proposals for depreciation expense are based) are the most conservative with respect to removal costs given that the study results indicate that more dollars *could* be assigned to removal using cost assignment data from field experts.

Table II-11 [36]

Comparison of Cost Assignment Ratios Across Three Studies Relative to the Standard Rates Table

(Stated as Percentage of Total Cost)

FERC Account	Description	Standard Rates Table	2004 Study	2006 Study	2016 Study
Transmission Plant					
354	Towers and Fixtures	Not Applicable - Non-Mass Plant			
355	Poles and Fixtures	27.2%	30.2%	31.4%	Not Studied
356	Overhead Conductors & Devices	42.1%	56.1%	56.7%	Not Studied
Distribution Plant					
364	Poles, Towers and Fixtures	36.6%	43.0%	39.4%	46.1%
365	Overhead Conductors & Devices	34.7%	38.6%	37.1%	35.6%
366	Underground Conduit	20.0%	42.3%	41.9%	41.7%
367	Underground Conductors & Devices	34.7%	32.1%	33.7%	35.7%
368	Line Transformers	27.3%	47.4%	48.8%	41.6%
369	Services	35.5%	44.2%	44.5%	33.8%
	Weighted Average*	33.0%	38.8%	38.3%	37.5%

**Weighted by 2009-2015 Recorded Net Salvage*

a) 2004 Study [37]

In the 2004 Study, performed for the 2006 GRC, SCE assembled field operations experts who compiled and analyzed work requirements for replacement projects of various assets under many different scenarios. The 2004 Study approached replacement costs from the perspective of SCE operations and maintenance personnel who had an average of 21 years of experience working with T&D assets. These subject matter experts, who had experience performing and supervising work activities, reviewed and assessed the time and work requirements for each of several scenarios including total time spent on the project, equipment requirements, and crew size requirements. The work activities were evaluated and separated into installation and removal activities. The experts compared the results from the study to the existing allocations in the Standard Rates Table and determined that no update to the Standard Rates Table was required because the estimated costs of removal were not overstated using the existing process.

[36] The nine accounts listed on this table are the same ones for which SCE performed a per-unit analysis. Refer to WP SCE-09 Vol. 03, Book A, pp. 42-46 (Summary of Study Results).

[37] Refer to WP SCE-09 Vol. 03, Book A, pp. 52-172 (2004 Study Results).

In preparing this testimony, SCE revisited the rebuttal testimony of its outside depreciation expert from the 2015 GRC. Appendix A of the witness's rebuttal testimony was a copy of the 2004 study, and, in response to a question about the "historical documentation describing . . . the development of allocation factors used by SCE," the witness referred to the 2004 study in Appendix A (among other things) as evidence that "SCE used a very robust and detailed process to develop its allocation factors."[38] As a point of clarification, the allocation factors to which the witness referred in his testimony are not the Standard Rates Table allocations that formed the basis of SCE's depreciation request in the 2015 GRC and this 2018 GRC.[39] Rather, the witness testified to the allocation process and results from the 2004 Study together with his own observations and discussions with field personnel about cost assignment. Any lack of clarity in distinguishing between the Standard Rates Table allocations and the 2004 Study's allocations is not material as demonstrated in Table II-11, above. In fact, the results of the 2004 Study would have assigned a larger percentage of costs to removal than does the Standard Rates Table (by approximately 5%), as shown in that table.

b) <u>2006 Study</u> [40]

In 2006, SCE updated the 2004 Study in preparation for the 2009 GRC. Using a similar approach to the one utilized for the 2004 Study, SCE assembled a team of field operations experts to gather consensus estimates for labor hours for the job configuration scenarios used in the 2004 Study. The panel of study participants included overhead and underground experts from metropolitan and rural areas of SCE's service territory and others who reviewed job conditions, crew sizes, and labor hour estimates. In addition, as an enhancement to the 2004 Study, the field experts weighted the installation and removal activities by the likelihood of the scenarios' occurrence in the field. The results from the analysis were compared to the Standard Rates Table allocations, and the experts determined that if they were to update the Standard Rates Table allocations to incorporate the results of the 2006 Study, the cost of removal allocations would increase by over 5%. For this reason, and because SCE planned to implement new work planning and accounting software in 2010, SCE elected to continue using the Standard Rates Table.

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[38] 2015 GRC, SCE-26, Volume 3, p. 13. Later in the same volume, SCE's witness testified that the study in Appendix A shows that "the allocation factor <u>will</u> change based on more complex installations." *Id.*, p. 115 (emphasis in original). This was a reference to the study results, not to the way in which the Standard Rates Table allocations are applied today.

[39] The Standard Rates Table was used to assign costs for several GRCs even prior to 2015.

[40] Refer to WP SCE-09 Vol. 03, Book A, pp. 173-188 (2006 Study Results).

c) 2016 Study

(1) Background of Development of Compatible Units (CUs).

Before explaining the results of the 2016 Study, it is important to understand the development beginning in 2009 of the CUs that T&D employees use to plan, estimate, schedule and bill work. As explained in section II.C.2, above, DM incorporates the use of over 4,500 distribution CUs to assist planners with building cost estimates and scheduling work depending on the specific requirements of the job. When CUs are migrated to PowerPlan, they are mapped to CPRs and, for fixed asset accounting purposes only, the Standard Rates Table is used to allocate costs between removal and installation. The labor hours embedded in the CUs in DM are not used in the cost allocation process, but are important to facilitating the planning, scheduling, execution and closure of work orders for the T&D Operating Unit.

(2) 2009-2010 Labor Study

In 2009-2010, SCE undertook a year-long process to review and update the precursors to CUs, called "assembly kits," in preparation for integration into DM and SAP. This effort to examine CU hours was internally referred to as the "Labor Study," and it leveraged the results of the 2004 and 2006 Studies described above. The participants in the Labor Study—including construction managers and supervisors, foremen, trouble men, and standards and engineering teams from across SCE's service territory[41] — examined over 4,500 CUs of distribution assets and modified 1,800 of them.[42] The purpose was not to modify CUs for depreciation plant accounting purposes; rather, the intent of the study was to refine the "building blocks" of SCE's thousands of work orders (CUs) to improve planning, crew scheduling, estimating and pricing jobs and work order closure processes.

For three to four months of eight-hour days, the teams went line-by-line through SCE's old Material Management System (the old mainframe system in which the assembly kits resided) to remove obsolete items.[43] The initial part of the Labor Study was devoted to just clearing SCE's planning system of obsolete assembly kits. In the latter phase, the teams updated the labor hours

41 Specifically, the experts came from the Metro West, Metro East, North Cost, Desert and Orange areas of SCE's service territory.

42 Separately, approximately 3,900 CUs for substation and sub-transmission assets were reviewed and migrated into SAP.

43 For example, if the Material Management System referred to a transformer with certain voltage requirements that were no longer applicable, that assembly kit was removed.

of the most commonly used CUs—transformers, switches and poles. The goal was to approximate labor hours as precisely as possible in order to improve crew scheduling times and cost estimates.[44] The team based labor hour estimates on the expert judgment and analysis of T&D employees, taking into consideration factors such as crew size, whether the work is performed energized, and whether the crews would have vehicle access. The work also involved examining individual CUs to assign updated removal and installation hours. The end result of the panel of experts' process was to review—and, if necessary, revise—the installation and removal hours (the removal hours assigned in the old assembly kits had been set at roughly half of installation hours). The updated labor values were developed using an average of the best, typical and worst case scenario specific to the installation and removal of a CU.

By 2010, the update process for the CUs had been completed, but SCE uses an ongoing governance structure to further update CUs on an ad hoc basis when required. There are three full-time employees whose job is focused on maintaining and updating CUs so that proposed/required changes flow through a standard process. The CU team receives an average of 22 requests each year to create new CUs (from planning, engineering, apparatus and meter services). The team also receives approximately 60 requests each year to review the accuracy of specific CUs (requesting review of hours or material components). Of the approximately one thousand field requests that have come through to examine CUs since 2010, less than a handful of requests actually resulted in changes to the installation/removal hours. This is due both to the comprehensiveness of the 2009-2010 Labor Study and the reality that work processes/practices do not change so significantly over time as to impact cost of removal ratios.

When planners use CUs to design and estimate particular jobs, they may—based on their own experience or through discussions with field personnel—supplement the labor estimates with additional Install, Removal or Expense labor hours on a work order-by-work-order basis. Any changes made to the project based on job complexity, additional crew tailboards, additional traffic control requirements, travel time, etc. are used for that specific work order only, and do not result in updating the master CU in the CU library. Updates to the CUs in the CU library occur occasionally. For example, in August 2012, a manager within the Street and Outdoor Lighting Organization requested that the CU team review the installation hours for street light photocells given his assessment that the 0.5

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[44] Work under Rules 2, 15, 16 and 20 benefit from accurate cost estimates built into CUs because those estimates form the basis for how customers are billed.

man hours for installation of this CU appeared high. The CU team pulled together a team of subject matter experts to assess and recommend a revision to the hours and determined that it should be reduced to 0.1 hours. Upon approval, the update was made in DM.

(3) 2016 Comparison of Standard Rates Table and CUs

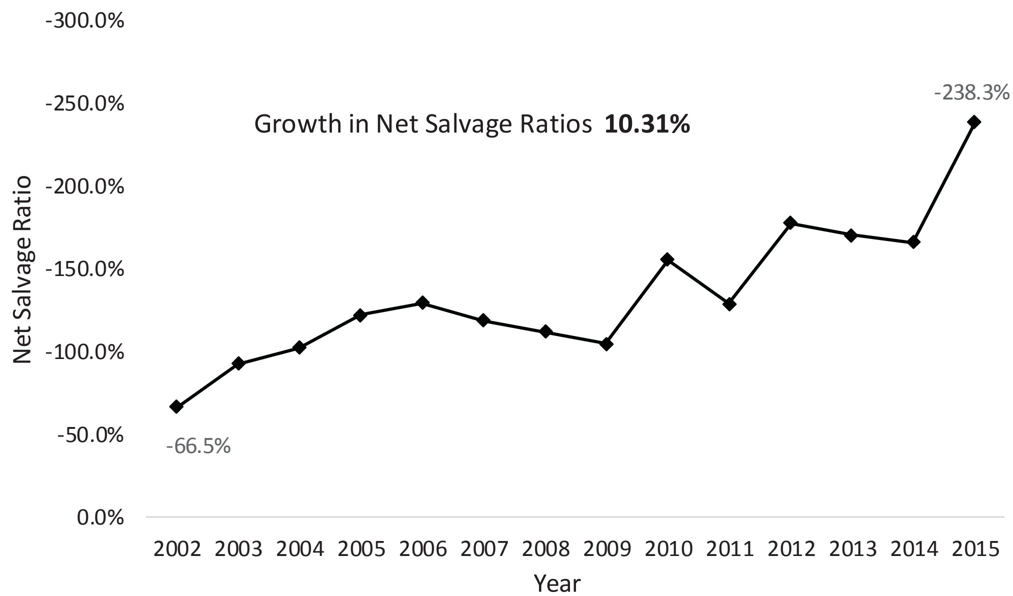
In 2016, SCE undertook a study comparing the Standard Rates Table allocations with what the allocations would be if SCE's fixed asset accounting process mapped the CU process described above. The scope of the study included a review of over 70,000 individually planned distribution orders developed in Design Manager in 2015, which collectively amounted to $1.7 billion, or approximately 84% of that year's capital expenditures. The review included comparing the installation and removal cost allocation from DM against the Standard Rates Table allocation for all 70,000 orders. The results indicate that the planners' CU-based approach, which is more detailed than the higher-level aggregation of the CPR-based allocations in the Standard Rates Table, results in cost assignments substantially similar to the Standard Rates Table (validated by the 2004 and 2006 Study results based on the panels of T&D experts).[45]

D. SCE's Experience with Increasingly Negative Net Salvage Rates

NSRs are typically negative because gross salvage is largely negligible compared to the cost of removal. The main reason for more negative NSRs can be attributed to the results of this mathematical formula: (1) costs to retire assets (numerator) in today's dollars divided by (2) the age and original cost of assets retired (denominator). Since 2002, SCE's 5-year rolling average NSR has more than tripled for distribution infrastructure, from -66% to -283% as shown in Figure II-7 below.

[45] Refer to WP SCE-09 Vol. 03, Book A, pp. 189-197 (2016 Study Results).

Figure II-7
Realized Net Salvage Ratios
Distribution Plant 2002-2015



For the last twenty years, SCE has experienced increasingly negative net salvage ratios for reasons explained in the next sections.

1. <u>The Average Age of Retirements is Increasing</u>

a) <u>Age and Inflation Impacts on Recorded Net Salvage Ratios</u>

An important consideration for the net salvage ratio calculation is that the numerator (net salvage cost) and the denominator (original cost) are stated in dollars spent at different points in time. The original cost retired in the denominator are measured in dollars from the time the plant was first placed in service (*i.e.*, older dollars) and the net salvage amounts in the numerator are measured when the plant is retired from service (*i.e.*, using more recent dollars). For example, a distribution pole placed into service in 1970 and retired in 2015 will have an original cost stated in 1970 dollars, but the removal costs will be incurred using 2015 dollars. Consequently, the temporal distance between installation and removal can have a significant effect on net salvage ratios primarily due to the effects of inflation. The effects of inflation are most apparent in the removal cost ratio, as the cost to retire (*i.e*., labor) is what is subject to the forces of inflation.[46]

[46] Refer to WP SCE-09 Vol. 03, Book A, pp. 198-201 (Experienced Net Salvage Rates) - *Depreciation Systems*, Frank K. Wolf and W. Chester Fitch, Iowa State University Press, pp. 53-55.

To illustrate the impact of inflation using a real life example, Table II-12, below, shows that the removal cost ratio increases with the age of the pole retired. Column C reflects the original cost of the pole being retired, while column D represents the removal cost in current dollars.

Table II-12
Plant Retirement and Removal Cost
(As Experienced for Distribution Poles – Account 364)
Data based on averages from 2009 to 2015

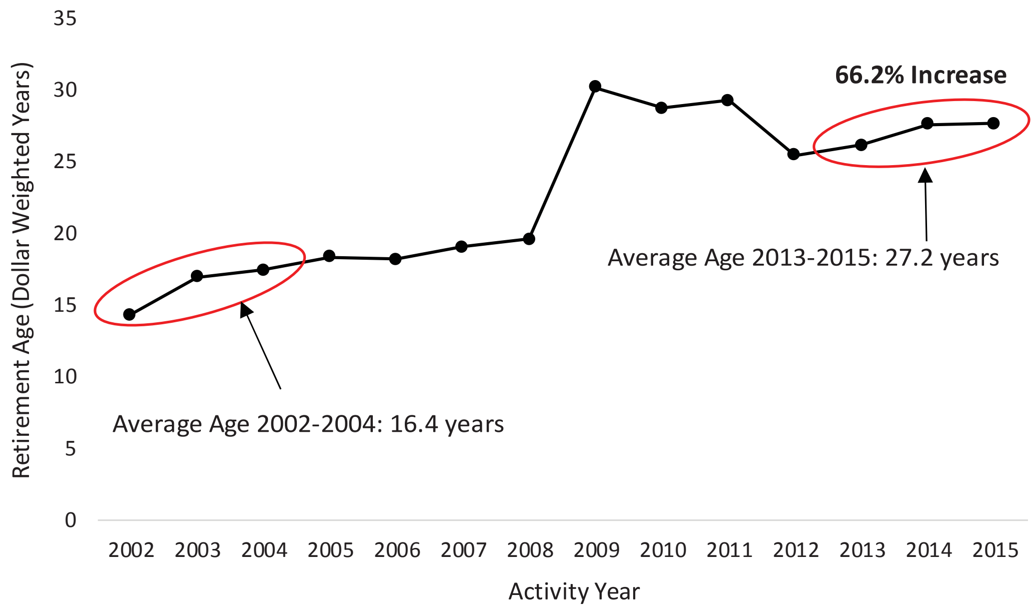
Vintage	Age of Pole Retired	Original Cost of Pole Retired	Per Pole Removal Cost	Removal Cost Ratio
A	B	C	D	E=D/C
2010	2.5	$7,599	$2,862	38%
2000	12.5	$3,547	$2,862	81%
1990	22.5	$1,413	$2,862	203%
1980	32.5	$622	$2,862	460%
1970	42.5	$369	$2,862	775%
1960	52.5	$167	$2,862	1717%

The table above demonstrates that as the age of the asset retired grows, the effects of inflation have an increasingly large impact on the realized removal cost ratio. This occurs because the average cost to install a pole in 1960 (Column C) would be significantly lower than the average cost to install a pole today, while the cost to remove each pole (Column D) is the same regardless of the age of the pole retired.

b) SCE's Aging Retirements

For multiple GRCs, T&D experts have testified about the advancing age of SCE's infrastructure. As the system matures, the average age of any retirement can be expected to be older than what was experienced in the past. As the system ages, the incidence of age related failures will increase. In fact, as shown in Figure II-8, below, this has been SCE's experience with distribution infrastructure for the past 13-years.

Figure II-8
Average Age Of Distribution Infrastructure Retired



As the age of T&D retirements increases, the original cost of the retirements has remained low, resulting in an increase in the experienced net salvage ratios.

2. <u>Total Cost Increases Affect Cost of Removal</u>

Over the last several rate cases, T&D experts have testified to the increasing need for capital to replace aging T&D infrastructure. This capital (including both the cost to remove and install) has been discussed by multiple witnesses over more than a decade of rate cases. In each case, witnesses have testified to cost pressures from the effects of: increasingly urban environments, increasing labor and contractor rates, increased permitting costs, more stringent environmental regulations, disposal fees, and system complexity.

For example, in the 2006 GRC the T&D Infrastructure Replacement witness provided the following still-relevant discussion on why the cost to retire assets in urban environments is higher than in rural areas:[47]

1) <u>Permitting</u>: Pole contractors are almost always required to obtain a city permit before initiating the work. In rural areas, permits are almost never required.

[47] 2006 GRC SCE-03 Vol 03 Part III pp. 14-15 and 2009 GRC SCE-03 Vol 03 Part III pp. 20-21.

2) Accessibility: Urban areas are frequently inaccessible by trucks and require that a crane be rented or that the pole be carried into the back yard and set manually. Rural areas are typically truck-accessible.

3) Congestion: Higher customers per circuit in urban areas contribute to higher congestion per pole than in rural areas. For example, an urban pole can be expected to be taller, as well as have more conductors, transformers, and cross-arms than a rural pole. In addition, the work may be performed on energized lines requiring specially trained crews and safety requirements.

4) Repairs: Urban areas frequently require that repairs are made to the concrete sidewalks, a requirement not typically necessary in rural areas.

Los Angeles County's population experienced significant growth[48] in the post-World War II period through the 1970s. This post-war population growth has increased the level of urbanization across SCE's service territory, putting upward pressure on costs. As a result of this, when assets originally installed in a rural environment are removed, the net salvage ratio reflects a very low original install cost for these assets. But these same assets are likely being replaced in a now more urban environment, adding to the upward pressure on removal cost. This experience can have a significant effect on the net salvage ratios—lower original cost (denominator) and higher cost of removal (numerator).

Given the increasing age of this infrastructure and the increasing urbanization associated with the post-war population growth, increases in the realized net salvage ratios is not surprising. As a result, however, the conditions present in SCE's service territory over this period of time may not be a realistic expectation of the future. In this case, and as further discussed immediately below, a per-unit analysis controls for this variation, and better represents SCE's expectation about the future levels of net salvage.

3. SCE's Per-Unit Analysis is Indifferent to the Realized Net Salvage Ratios

As described in Section B.1 of Chapter II, a per-unit analysis takes a different approach than Standard Practice U-4 in analyzing the expected levels of future net salvage. Rather than reviewing the relationship between historical costs of assets and the net salvage experienced in the past, the per-unit analysis uses the recorded average cost to retire each unit of property, and then applies per-unit

[48] 2009 GRC SCE-03 Vol 03 Part 3 p. 15 (SCE Territory – Population and System Demand).

costs to existing plant balances to forecast future net salvage given the anticipated timing of retirements. This approach to estimating future net salvage helps ensure that the results of the analysis are applicable to the mixture of plant that is serving customers today. Over time, as this mix of plant balances change, SCE will have the opportunity to reflect these changes in future per-unit analyses presented in its rate cases.

III.

DEPRECIATION STUDY

Chapter II, above, explained how SCE complied with the Commission's compliance directives and addressed the difference between traditional and per-unit analyses. The depreciation study addressing T&D assets, presented in Section A in Q&A format, was undertaken by an external consultant, Ronald E. White Ph.D. of Foster Associates Consultants, LLC. Dr. White provided SCE with life and net salvage parameters that SCE then used to calculate the proposed depreciation rates. SCE also conducted an in-house depreciation study of its Generation and G&I depreciable plant assets, discussed by an in-house SCE expert witness in Section B, below.

Unlike the Simulated Plant Record (SPR) procedure used in prior SCE rate cases, Dr. White performed an *actuarial* service life analysis using aged data from 2002 to 2015. In the 2012 GRC, the Commission stated that aged data is likely to be more reliable than SPR data, and it ordered SCE to "inform the Commission whether it used any aged data, and if not, when sufficient data is expected to be available."[49] In its 2015 GRC testimony, SCE stated that it began collecting aged data in 2008 and that it did not have sufficient aged data to perform an effective actuarial life analysis for the 2015 GRC.[50] This statement was based on an incorrect assumption that the Company began collecting aged data in 2008 when it implemented PowerPlan as its capital system of record.[51] In preparing its showing for this proceeding, SCE discovered that PowerPlan contains reconciled aged plant activity from 2002 forward. Thus, for this GRC, Foster Associates LLC performed an actuarial life analysis using the aged data from 2002 to 2015.[52]

Section A of Chapter III, below, which is in Q&A format, is the direct testimony of Dr. Ronald E. White of Foster Associates LLC.

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49 D.12-11-051 p. 685.

50 *See* Testimony in 2015 GRC, SCE-10, Vol. 02, Revision 1A, p. 33. SCE stated that it expected that aged data may become useful "in 10 years or so." *Id*.

51 PowerPlan was used only as the depreciation system of record prior to 2008.

52 SCE possesses some aged retirement data from 1994 through 2001 in Excel format outside of SCE's current capital system of record (PowerPlan). Neither SCE nor its outside expert evaluated or relied on the aged data in the 1994-2001 Excel sheets.

A. T&D - Average Service Life and Net Salvage Proposals

1. Development of Depreciation Rates

Q. PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES.

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval.[53] A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life) system of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated firm. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the

[53] The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.

Q. PLEASE DESCRIBE THE PRINCIPAL STEPS INVOLVED IN CONDUCTING A DEPRECIATION STUDY.

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and cost of removal. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the Company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

Average and future net salvage rates are ideally estimated from a historical analysis of the cost per unit to install and the net cost per unit to retire major retirement units. A per unit analysis explicitly recognizes that the cost per unit to retire an asset is independent of the age of the asset when it is retired from service. The cost to retire a foot of conductor today, for example, is no different for a conductor that was installed yesterday or a conductor that was installed many years ago. As a result, percentage rate required to accrue for $5 per foot of removal expense on a conductor costing $10 per foot to install is twice the rate required to accrue the same amount of removal expense on a conductor costing $20 per foot to install.

Although a per unit analysis of installation and retirement costs is the most desirable treatment of net salvage, time and cost considerations (as well as the availability of the required data) often dictate a less rigorous analysis. Net salvage rates are frequently developed from a historical analysis using a three to ten–year moving average of the ratio of realized salvage and cost of removal to associated retirements. Net salvage estimates are also obtained from engineering studies of the cost to dismantle or abandon existing facilities.

2. <u>2016 Service–Life Study</u>

Q. DID SCE PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR ESTIMATING SERVICE LIFE PARAMETERS?

A. Yes. Service life statistics estimated in the 2016 study were derived from plant accounting transactions recorded over the period 2002 through 2015. Detailed accounting transactions were extracted from the Continuing Property Record (CPR) system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

The accuracy and completeness of the assembled database was verified for activity years 2002 through 2015 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Age distributions of surviving plant at December 31, 2015 were reconciled to the CPR.

Q. HOW WERE SERVICE–LIFE ESTIMATES DERIVED FOR SCE PLANT AND EQUIPMENT?

A. As noted above, the first step in estimating service lives is called *life analysis*. All transmission, distribution and general depreciable plant accounts were analyzed using a technique in which first, second and third degree polynomials were fitted to a set of observed retirement ratios. The resulting function was expressed as a survivorship function, which was numerically integrated to obtain an estimate of the average service life. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life curve for each plant category. The analysis of each plant account is contained in Appendix A.

Q. PLEASE EXPLAIN IN GREATER DETAIL HOW LIFE ANALYSES WERE CONDUCTED IN THE 2016 STUDY.

A. The fundamental probability distribution of interest in estimating the service life of industrial property is called a *hazard function*. This function, which is also used in reliability theory, is an equation that describes the conditional probability of retirement (called a *hazard rate*) during an age interval given survival to the beginning of the interval. So, for example, the probability that plant that has been in service, say for 5 years, will be retired during the 6th year is a conditional probability of retirement. In other words, the probability is conditioned upon having achieved an age of 5 years.

Graduating or smoothing observed hazard rates is an application of inferential statistics which draws inferences and predictions about a population based on samples of data taken from the population of interest. Projection lives and projection curves are population parameters "inferred" from a statistical analysis of the underlying forces of retirement described by probability distributions.

The object of a statistical analysis of plant retirements is to find the form of an equation that best describes the conditional probabilities of retirement, where the form of the equation is driven by the underlying forces of retirement. Any number of equations can be considered as candidates for selection. The so–called Iowa curves are a family of distributions most often used in conducting depreciation studies.

Each Iowa curve has a unique hazard function derived from the ratio of its retirement frequency distribution to its survivor distribution. Unfortunately, however, Iowa hazard functions cannot be written as explicit equations. It is for this reason that polynomials of the form $y = a + bx + cx^2 + dx^3$ are used to estimate hazard functions. The variable y is the hazard rate and x is the age interval of the rate.[54] A polynomial can be transformed into a survivor function and plotted against an Iowa curve to visually observe the derived survivor curve expressed as an Iowa curve.

The problem, therefore, is to estimate the coefficients (*i.e.*, *a*, *b, c* and *d*) of the polynomial from an estimate of hazard rates derived from a sampling of historical retirements recorded for a plant category. Different estimators of the hazard rate can be used depending upon the desired statistical properties of the estimator. The ratio of retirements to exposures is most often used for depreciation studies.

Coefficients were estimated in the 2016 study using *Orthogonal Polynomials.* An orthogonal polynomial is not a special form of a polynomial. It is a procedure developed by Tchebysheff to estimate the coefficients of a polynomial (using regression) without rewriting the normal equations for each successive power of the polynomial. The coefficients of a second degree equation, for example, can be derived from a first degree equation without rewriting the equations used in a normal least squares regression.

Coefficients and polynomials were estimated for numerous trials or samples of retirements recorded over various bands of activity years. An activity year is the calendar year in which retirements were recorded. Retirements from vintages of like ages are combined to increase the size of the samples from which hazard rates are estimated. The motivation for examining various bands of activity years is to observe service–life trends to the extent they may be detectable.

Each polynomial was transformed or converted to a survivor function (or survivor curve when plotted) from which an estimate of the projection life was derived. The polynomial form of the hazard functions were also plotted and visually inspected as an aid to better understanding the forces of retirement acting upon a plant category.

Polynomials transformed to survivor functions were then fitted to Iowa–type curves with projection lives set equal to those derived from the polynomials. The purpose of fitting to Iowa curves is to obtain service–life descriptors more familiar to users of Iowa curves. It would be more obscure and less informative to describe survivor curves by the coefficients of a polynomial.

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[54] The reason polynomials are limited to a third degree term (*i.e.*, a polynomial having an x^3 term) is that some low modal Iowa curves exhibit two inflection points in a plot of the hazard function.

Q. WERE FACTORS OTHER THAN SERVICE–LIFE INDICATIONS DERIVED FROM THE STATISTICAL STUDIES CONSIDERED IN ESTIMATING SERVICE–LIVES FOR SCE?

A. Yes. As discussed earlier, estimating service lives is a two–step procedure. The first step (life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of past forces of retirement acting upon a plant category and an estimate of the projection life implied from observed historical experience.

The second step (life estimation*)* is concerned with predicting the expected remaining life of property units still exposed to forces of retirement and the service life of future plant additions. It is a process of blending the results of a life analysis with information (mostly qualitative) and informed judgment to obtain an appropriate projection life and curve descriptive of future expectations. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future. Both life analysis and life estimation require an understanding of the limitations of statistical studies and the need for reasonable and informed judgment.

Q. ARE FACTORS YOU CONSIDERED IN LIFE ESTIMATION DESCRIBED IN THE 2016 STUDY?

A. Yes. Appendix A contains a narrative explanation of both quantifiable factors (life analyses) and non–quantifiable factors (largely life estimation) considered by Foster Associates in recommending appropriate projection lives and curves for SCE. In those instances in which statistical indications could not be derived and/or observed indications were adjusted for operational, financial or ratemaking reasons, Foster Associates deferred to SCE in the selection of appropriate service lives.

Q. IS A PROJECTION LIFE THE SAME AS AN AVERAGE SERVICE LIFE?

A. No. A projection life is an estimate of the mean service–life of the population from which retirements are a random sample. The *average* service life of a plant category is a function of the age distribution of surviving plant (*i.e.*, plant currently in service by vintage–year of installation) and a selected level of asset grouping such as broad–group, vintage–group or equal-life group. If retirements are distributed over varying ages, the broad–group procedure (which assumes that each vintage has the same average service life) is the only grouping of assets that will produce an average service life equal to the projection life estimated for a plant category.

Q. PLEASE SUMMARIZE THE FINDINGS OF YOUR SERVICE–LIFE STUDY.

A. Current and recommended projection lives and dispersions are summarized in Table III-13 below.

Table III-13
Service Life Statistics

Account Description	Current		Recommended	
	P-Life	Dispersion	P-Life	Dispersion
A	C	D	E	F
Transmission Plant				
352.00 Structures and Improvements	55.00	S3	55.00	L1
353.00 Station Equipment	45.00	R0.5	40.00	L0.5
354.00 Towers and Fixtures	65.00	R5	65.00	R5
355.00 Poles and Fixtures	50.00	R0.5	65.00	SC
356.00 Overhead Conductors and Devices	61.00	R3	61.00	R3
357.00 Underground Conduit	55.00	R3	55.00	R3
358.00 Underground Conductors and Devices	40.00	R2.5	45.00	S1
359.00 Roads and Trails	60.00	SQ	60.00	R5
Distribution Plant				
361.00 Structures and Improvements	42.00	R2.5	50.00	L0.5
362.00 Station Equipment	45.00	R1.5	65.00	L0.5
364.00 Poles, Towers and Fixtures	47.00	L0.5	55.00	R1
365.00 Overhead Conductors and Devices	45.00	R0.5	55.00	R0.5
366.00 Underground Conduit	59.00	R3	59.00	R3
367.00 Underground Conductors and Devices	45.00	R0.5	43.00	R1.5
368.00 Line Transformers	33.00	R1	33.00	S1.5
369.00 Services	45.00	R1.5	45.00	R1.5
370.00 Meters	20.00	R3	20.00	R3
373.00 Street Lighting and Signal Systems	40.00	L0.5	48.00	L1
General Plant				
390.00 Structures and Improvements	38.00	R3	45.00	R0.5

Table 1. Service Life Statistics

3. <u>2016 Net Salvage Study</u>

Q. WHY IS NET SALVAGE RECOGNIZED IN THE COMPUTATION OF DEPRECIATION ACCRUAL RATES?

A. Depreciation is a measurement of the service potential of an asset that is consumed during an accounting interval. The cost of obtaining a bundle of service units (*i.e.,* a future net revenue stream) is represented by an initial capital expenditure which creates a revenue requirement for return and depreciation, and a future expenditure which creates a revenue requirement for cost of removal reduced by salvage proceeds. The matching principle of accounting provides that both the initial and future expenditures should be allocated to the accounting periods in which the service potential of an asset is consumed. The standard or criterion that should be used to determine a proper net salvage rate is, therefore, cost allocation over economic life in proportion to the consumption of service potential. If some other standard (such as cash flow or revenue requirements) is considered more important in setting depreciation rates, then cost allocation theory must be abandoned as the foundation for depreciation accounting.

The need to include net salvage in the development of depreciation rates is widely recognized and accepted by a substantial majority of state regulatory commissions as a standard ratemaking principle. The FERC Uniform System of Accounts (USoA), for example, describes depreciation as the "… loss in service value" where service value is defined as "… the difference between original cost and net salvage value of gas plant." Net salvage value means "the salvage value of property retired less the cost of removal."

The economic principle underlying both the accounting and ratemaking treatment of net salvage is that in addition to return *of* and return *on* invested capital and taxes, a revenue requirement for removal expense (or a reduction in the revenue requirement attributable to gross salvage) is created when an asset is placed in service. It is customary and appropriate for regulated utilities, therefore, to include a net salvage component in its depreciation rates to more nearly achieve the goals of depreciation accounting and to equitably distribute the revenue requirement for removal expense over the period in which the assets that created the requirement are used to provide utility service.

Q. WHAT IS A FUTURE NET SALVAGE RATE?

A. Future net salvage (in percent) is the sum of future net salvage (*i.e.*, gross salvage less cost of removal) at a given observation age divided by the surviving plant investment at that age.

Q. WHAT IS AN AVERAGE NET SALVAGE RATE?

A. Average net salvage (in percent) is the sum of realized and future net salvage divided by the plant investment at age zero. Stated differently, average net salvage is the total estimated salvage less cost of removal for a vintage (or group of vintages) expressed as a percent of the original vintage additions. Future net salvage is related to the surviving plant of a vintage (or group of vintages) whereas average net salvage is associated with the original vintage addition.

Q. ARE YOU FAMILIAR WITH THE COMMISSION'S DECISION IN SCE'S 2015 GRC (D.15-11-021) REGARDING NET SALVAGE PROPOSALS?

A. Yes. In the 2015 GRC Decision, the Commission directed SCE to provide more detail in support of its net salvage proposals for at least five of the largest accounts, as measured by proposed annual depreciation expense. At a minimum, this detail shall include:

1. "A quantitative discussion of historical and anticipated future Cost of Removal (COR) on a per unit basis for the large (greater than 15% as measured by the portion of plant balance) asset classes in the account. This discussion should identify and explain the key factors in changing or maintaining the per–unit COR."
2. "A quantitative discussion of historical and anticipated future retirement mix (i.e., retirements among different asset classes), identifying and explaining the key factors in changing or maintaining this mix."
3. "A quantitative discussion of the life of assets and original cost of assets being retired, in relation to the COR, on both a historical and anticipated future basis. This discussion should be integrated with and/or cross–reference the proposal for life characteristics."
4. "An account–specific discussion of the process for allocating costs to COR."[55]

a) Directive No. 1

Q. WERE HISTORICAL AND FUTURE NET SALVAGE COSTS DERIVED ON A PER UNIT BASIS IN COMPLIANCE WITH THE COMMISSION'S FIRST DIRECTIVE?

A. Yes. Per unit net salvage analyses were conducted for the nine (9) plant accounts listed in Table III-14, below.

[55] D.15-11-021, pp. 554-555.

Table III-14
Per Unit Net Salvage Accounts

Account Description
354.00 Towers and Fixtures
355.00 Poles and Fixtures
356.00 Overhead Conductors and Devices
364.00 Poles, Towers and Fixtures
365.00 Overhead Conductors and Devices
366.00 Underground Conduit
367.00 Underground Conductors and Devices
368.00 Line Transformers
369.00 Services

Table 2. Per Unit Net Salvage Accounts

Each of the nine plant accounts was grouped into one or more subpopulations of major equipment categories. Historical per unit ratios (defined as net cost per unit to retire divided by the cost per unit to install) were used in both the historical and future per unit analyses. Net costs to retire (or net salvage) were used in the analysis to maintain consistency with future net salvage parameters used in the formulation of remaining–life accrual rates. Gross salvage is generally small in relation to cost of removal.

Historical per unit ratios were examined and compared with the ratio of realized net salvage to the associated retirements. In most instances, the ratio of net salvage to retirements is greater than historical per unit ratios observed over the period 2009–2014. This is predictable since net savage is recorded in current dollars and retirements are recorded in historical dollars.

Future per unit ratios were derived using a weighted average of the subpopulation net salvage per unit values recorded over the period 2009–2015. These values appear in the numerator of future per unit ratios. This treatment was decided after multiple meetings and discussions with SCE engineers and subject matter experts who reported that SCE has no planned or expected changes in retirement activities that would measurably change average net salvage per unit values recorded in recent activity years. Other than recognizing future inflation, historical net salvage per unit values were therefore retained in the forecast of future net salvage rates. Subpopulations and average historical per unit net salvage costs are summarized in Table III-15 below.

Table III-15
Average Net Salvage Per Unit to Retire

Account and Subpopulation	12/31/2015 Plant	Percent	Avg. Add Per Unit*	Avg. NS Per Unit*
A	B	C	D	E
354.00 Towers and Fixtures				
A. Towers Soley Owned >= 230 kV	$ 1,139,621,027	91.8%	$610,475	$ 57,365
B. Towers < 230 kV, Common and Other	101,453,733	8.2%	321,711	6,628
	1,241,074,760	100.0%		
355.00 Poles and Fixtures				
A. Wood, Fiber Glass and Composite	375,781,560	47.2%	14,939	4,517
B Light Duty Steel	419,049,403	52.6%	18,775	10,281
C Retaining Walls	1,261,756	0.2%	145,988	(36,480)
	796,092,719	100.0%		
356.00 Overhead Conductors and Devices				
A. Conductor < 220 kV	202,769,129	18.7%	11	5
B Conductor >= 220 kV	739,015,019	68.3%	38	6
C Disconnect Switches	27,761,688	2.6%	42,650	11,921
D Ground Wire	113,151,541	10.5%	20	(46)
	1,082,697,377	100.0%		
364.00 Poles, Towers and Fixtures				
A Wood, Fiberglass and Steel Poles	2,191,572,261	100.0%	6,882	2,700
	2,191,572,261	100.0%		
365.00 Overhead Conductors and Devices				
A Overhead Conductor	946,696,334	68.6%	8	3
B Switches	347,104,388	25.1%	12,828	3,384
C Breakers, Reclosures and Other	87,013,183	6.3%	2,404	358
	1,380,813,905	100.0%		
366.00 Underground Conduit				
A Pull and Slab Boxes	447,741,061	13.0%	949	1,305
B Below Ground Conduit	789,932,796	22.9%	23	1
C Vaults	324,651,530	9.4%	7,584	23,101
D Excavation Trenches	16,836,983	0.5%	(77)	
E Manholes and Other	157,068,859	4.6%	1,258	462
	1,736,231,229	50.3%		
367.00 Underground Conductors and Devices				
A Underground Cable	4,452,641,073	84.6%	25	10
B Breakers, Switches, Reclosures	809,879,908	15.4%	8,567	4,896
	5,262,520,981	100.0%		
368.00 Line Transformers				
A Overhead Transformers	1,045,618,106	30.3%	2,655	561
B Underground Transformers	1,262,937,734	36.6%	5,899	1,459
C Lightening Arresters and Fuse Holders	749,306,101	21.7%	924	161
D Switches, Breakers, Capacitors, etc.	393,008,343	11.4%	5,658	960
	3,450,870,284	100.0%		
369.00 Services				
A Underground Conductor	783,834,596	61.2%	301	221
B Overhead Conductor	387,892,896	30.3%	236	123
C Risers	63,694,659	5.0%	881	450
D Underground Conduit and Other	44,872,497	3.5%	12	0
	1,280,294,648	100.0%		

*2009 - 2015

Table 3. Average Net Salvage Per Unit to Retire

The per unit cost of plant additions used in forecasting future net salvage rates was obtained by dividing vintaged plant in service at December 31, 2015 (*i.e.*, age distributions of surviving plant) by vintaged units in service within each subpopulation. The ratio of average net salvage per unit experienced over the period 2009–2015 (adjusted for inflation) to the per unit cost of plant in service is the ratio that was applied to forecasted retirements to estimate future net salvage for each vintage. The sum of future net salvage over all vintages divided by current plant account balances produces an estimated future net salvage rate for each primary account. The formulation of per–unit net salvage rates is contained in Appendix B.

Q. PLEASE SUMMARIZE THE FINDINGS OF YOUR PER UNIT NET SALVAGE ANALYSIS.

A. Future net salvage rates derived with inflation rates ranging between zero (0) and three (3) percent are summarized in below.

Table III-16
Future Net Salvage Rates

Account Description	Projection Curve	Inflation Rate			
		0%	1%	2%	2.72%
A	B	C	D	E	F
354.00 Towers and Fixtures	65-R5	104%	125%	155%	185%
355.00 Poles and Fixtures	65-SC	90%	155%	295%	499%
356.00 Overhead Conductors and Devices	61-R3	114%	141%	178%	210%
364.00 Poles, Towers and Fixtures	55-R1	180%	249%	361%	488%
365.00 Overhead Conductors and Devices	55-R0.5	195%	272%	397%	538%
366.00 Underground Conduit	59-R3	108%	170%	276%	401%
367.00 Underground Conductors and Devices	43-R1.5	112%	150%	205%	261%
368.00 Line Transformers	33-S1.5	27%	33%	40%	47%
369.00 Services	45-R1.5	178%	231%	309%	387%

Table 4. Future Net Salvage Rates

Q. HOW WERE NET SALVAGE RATES ESTIMATED FOR ACCOUNTS NOT INCLUDED IN THE PER UNIT NET SALVAGE ANALYSIS?

A. A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was used to: a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future. The analysis of net salvage is contained in Appendix A.

Although future per unit ratios applied to a forecast of future retirements provides a more rigorous estimate of future net salvage rates, it is the opinion of Foster Associates that the ratio of realized net salvage to retirements provides reasonable estimates of future net salvage rates to the extent that future inflation is similar to the past. Estimating depreciation rates, however, is not an exact science; errors of estimate in both service lives and nets salvage rates will always remain.

b) Directive No. 2

Q. WERE HISTORICAL AND FUTURE RETIREMENT MIXES EVALUATED IN COMPLIANCE WITH THE COMMISSION'S SECOND DIRECTIVE?

A. Yes. As noted above, each of the nine plant accounts was divided into one or more subpopulations of major equipment categories. The mix of equipment classified in each subpopulation and the size of each subpopulation as a percent of the current investment in each related plant account were reviewed by SCE engineering and plant accounting personnel. No key factors were identified from this review that would suggest the future retirement mix or relative size of each subpopulation will be significantly different from the current composition and grouping of subpopulations.

c) Directive No. 3

Q. WERE RECOMMENDED LIFE CHARACTERISTICS AND NET COST OF REMOVAL INTEGRATED IN COMPLIANCE WITH THE COMMISSION'S THIRD DIRECTIVE?

A. Yes. The directive to provide a quantitative discussion of asset life and original cost of assets being retired, in relation to the COR on a historical basis, was interpreted to mean an examination of the average age of retirements associated with the recording of COR. Work papers supporting Appendix A provide a summary (Schedule E) of the average age of retirements and recorded COR for each of the per unit accounts. Although net salvage is often recorded subsequent to the recording of retirements, it can be observed that COR as a percent of retirements is a function of the age of retirements and generally increases with increases in the average age.

As noted earlier, a prospective per–unit analysis should be designed to produce estimates of future net salvage rates respecting the principle that the net cost per unit to retire an asset in independent of the age of the asset when it is retired from service. The percentage rate applied to the cost of an old asset to accrue the same cost per unit to retire a newer asset, however, depends upon the relative difference in the cost per unit incurred to install the assets. Integration of per unit ratios with life characteristics necessitates forecasting vintaged retirements using projection lives and curves estimated for each plant account.

Estimates of the amount and timing of future net salvage were derived from an application of the ratio of per unit net costs to retire and per unit installed costs of each vintage within a subpopulation, to future retirements (forecasted by vintage) using the projection lives and curves estimated in the statistical life studies. Inflation rates ranging between zero and three percent were employed in the analysis to recognize the likelihood of increasing net salvage solely attributable to inflation.

Other than a range of assumed inflation rates and parameters estimated in the service–life studies, no elements of qualitative judgment were required or exercised in estimating future net salvage rates from the per unit analysis.

d) Directive No. 4

Q. THE COMMISSION'S FOURTH DIRECTIVE IN APPLICATION A.13–11–003 WAS TO PROVIDE AN ACCOUNT–SPECIFIC DISCUSSION OF THE PROCESS FOR ALLOCATING COSTS TO COR. HAS SCE COMPLIED WITH THIS DIRECTIVE?

A. Yes. The process for allocating costs is described in the direct testimony of SCE witness Alan Varvis in this Exhibit.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

B. Generation and G&I - Average Service Life and Net Salvage Proposals

1. Purpose and Scope

This chapter covers the average service lives and net salvage proposals for SCE's Generation and General & Intangible (G&I) assets. For G&I assets, SCE proposes to retain the same service lives and net salvage rates as authorized in the 2015 GRC Decision.

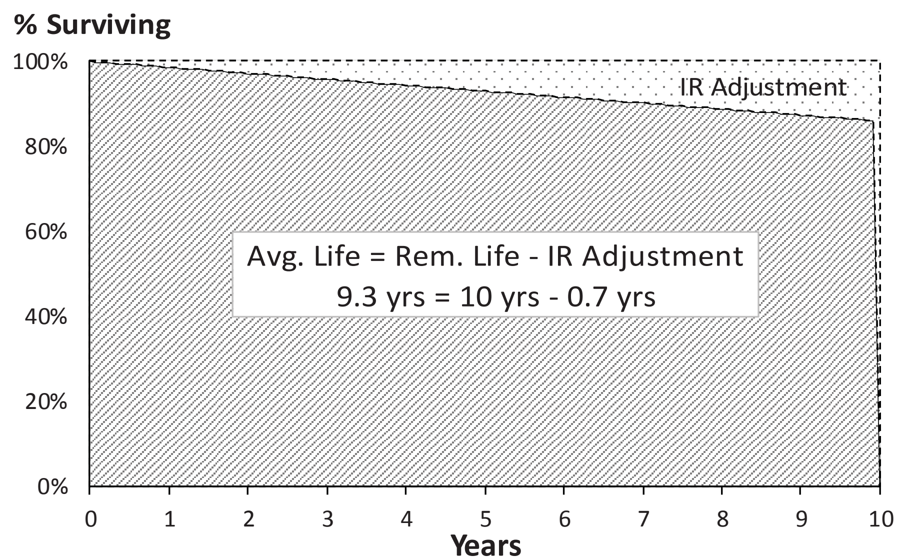
2. Generation-Related Property

a) Average Service Lives for Generation Assets

Generating facilities are life span assets that consist of large plant assets expected to retire all at one time, with some smaller components retiring earlier during the service life of the plant (called "interim retirements"). To determine the *average* life of the plant asset, SCE adjusts the life span downward to take into account the shorter-lived interim retirements. The life span for a generating facility as a whole depends on the factors affecting the final shutdown: operating license, fuel and resource availability, contractual obligations, the relative efficiency of the generating units, and so forth. The total life span is determined largely as an engineering judgment based on the factors previously mentioned.

Interim retirements consist of such items as pumps, motors, and other individual generating components that retire depending on the factors specifically affecting them—wear and tear, reliability, obsolescence, and so forth. The impacts of the life span and the interim retirements on the overall average service life of the plant asset are determined separately. SCE considered the interim retirement adjustment first by estimating the future level of annual interim retirements as a percent of the plant balance (*i.e.*, an interim retirement rate or IR rate). The estimate of an IR rate is made by analyzing the historical levels of interim retirements. The determined annual IR rate is applied to the current plant balance over the remaining life of the plant to determine the necessary adjustment to the overall remaining life of the generating station. For example, if a generating plant has a 10-year remaining life and an IR rate of 1.4 percent per year, then about 14 percent of the current plant balance would retire as interim retirements (10 years times 1.4 percent year) and the remaining 86 percent would retire as a final retirement. The resulting survivor curve is shown in Figure III-9.

Figure III-9
Life Span Survivor Curve*



** Remaining Life Span = 10 years; IR Rate = 1.4%.*

As Figure III-10 demonstrates, the average life is equal to the life span adjusted for the shorter life of the interim retirements. The remaining life adjustment is calculated as follows:

Figure III-10
Life Span: Remaining Life Adjustment

$$\text{Remaining Life Adjustment} = \frac{\text{Rem. Life Span x IR Rate}}{2} \text{ x } \text{Rem. Life Span}$$

$$\text{0.7 Years} = \frac{\text{10 Years x 1.4\%}}{2} \text{ x } \text{10 Years}$$

Table III-17 summarizes SCE's proposed generation average service lives as compared to those authorized in the 2015 GRC. What follows is a plant-by-plant discussion of the proposed average service lives.

Table III-17
Generation Service Life Spans

Generation Facility	Life Spans	
	Authorized	Proposed
A	B	C
Nuclear Production - Palo Verde	30.5 yrs	28.0 yrs
Hydro Production	26 yrs	19.9 yrs
Other Production		
Pebbly Beach	45 yrs	25 yrs
Mountainview	35 yrs	35 yrs
Peakers	35 yrs	35 yrs
Solar Photovoltaic	25 yrs	20 yrs
Fuel Cells	10 yrs	10 yrs
Energy Storage	N/A	10 yrs

(1) Palo Verde Nuclear Generating Station (PVNGS)

The Nuclear Regulatory Committee (NRC) licenses for PVNGS Units 1, 2, and 3 end June 1, 2045, April 24, 2046, and November 25, 2047, respectively, resulting in an average 30.5 year remaining life span for the station as of December 31, 2015. In addition, recent retirement activity supports adjusting the average remaining life down by 2.5 years to 28 years to account for the effect of interim retirements.

(2) Hydro Generation

SCE's hydro generation system consists of 76 generating units and associated facilities accounted for in 60 different accounting locations. Nearly all of SCE's hydro facilities (99 percent) is covered by FERC licenses. The licenses have a variety of termination dates—from expired (either in the process of being relicensed or decommissioned) to 2046. The total life span of SCE's current license periods for those plants without expired licenses range between 5 and 30 years. Recently, FERC has issued renewals with license periods averaging 40 years.

Prior license renewal does not guarantee that the generating plant will last indefinitely. There are no guarantees that the FERC will continue to grant the company licenses or that the generating units will continue to be economic. Moreover, the individual components making up a generating station will continue to wear out, be retired, and need to be replaced. Consequently, SCE proposes that the hydro generation plant be depreciated over the remaining life spans associated with the individual FERC licenses.[56] For generating stations with already expired, or within five years of license termination, SCE proposes that the life spans be extended by the estimated license life in its current FERC license applications.[57]

(3) Pebbly Beach

The Pebbly Beach generating station consists of six diesel generating units, ranging in capacity from 1.0 MW to 2.8 MW. In its last GRC, SCE was authorized a 45-year average service life for this account on the basis that each of the six units would experience increasing risk of obsolescence and failure after two overhaul cycles (approximately 22 years between overhauls). Because of the difficulty in sourcing alternative supply of generation for Catalina Island, SCE engineers expect these units to remain in-service for the foreseeable future. However, to help ensure continued operations, SCE engineers state that the units require a zero-time overhaul[58] after approximately 100 to 120 thousand operating hours. Based on SCE's actual experience with the operations of these units, the time between overhauls is approximately 25 years.

For example, the SCE is proposing to reduce the average service life for this account from the currently authorized 45 years to 25 years. This change is concurrent with moving the start of the amortization period from the vintage year to the date of the last overhaul. This 25-year life allows SCE to recover the cost of each zero-time overhaul over its useful life with little impact to the remaining life as shown in Table III-18 below.

[56] In the case of the 1 percent of hydro plant not covered by a FERC license, SCE applies the average life determined for the plant that is covered by FERC license.

[57] The average application license period is 44 years. The exception to this life span extension is the amortization period for the hydro relicensing costs. These relicensing costs are only amortized over the associated license period for which they were spent.

[58] A zero-time overhaul restores operations of the unit to like-new operating conditions.

Table III-18 [59]
Comparison of SCE's 2015 Authorized and 2018 Proposed Lives for Pebbly Beach Generating Station

Line No.	Item	2015 GRC Authorized	2018 GRC Proposed
1.	Average Start Date	1986	2006
2.	Proposed ASL	45	25
3. = 1.+2.	Estimated Ret. Date	2031	2031
4. = 3. - 2015	Rem. Life a/o 1/1/2016	15.7	15.5

There have been insufficient interim retirements to estimate an IR rate for this plant; consequently both the remaining life span and the average remaining life are 15.5 years for this account.

(4) Mountainview

SCE is proposing to retain Mountainview's currently authorized 35-year life span as established in the 2015 GRC Decision. There have been insufficient interim retirements to estimate an IR rate for this plant; consequently both the remaining life span and the average remaining life are 25 years for this account.

(5) Peakers

SCE is proposing to retain the currently authorized 35-year average service life for Peaker. There have been insufficient interim retirements to estimate an IR rate for this plant; consequently both the remaining life span and the average remaining life are 28 years for this account.

(6) Solar Photovoltaic

The currently authorized average service life for Solar Photovoltaic (PV) equipment is 25 years. SCE is proposing to return to the previously authorized 20-year average service life. Based on discussions with SCE engineers[60] the major components of this account will have significantly shorter service lives than the currently authorized 25-year life. Engineers indicate that the

[59] Refer to WP SCE-09 Vol. 03, Book A, p. 203 (Generation Life Spans).
[60] Refer to WP SCE-09 Vol. 03, Book A, p. 204 (Generation Life Spans).

equipment in this account is expected to fail significantly sooner than the currently authorized 25-year authorized life. For example, the three main components[61] include:

- Solar Panels – 10-12 years
- Inverters – 5-8 years (warrantied for 5 years)
- Control System – 6-8 years for obsolescence to set in.

In addition, the rooftop leases granting SCE the rights to use the rooftop facilities is currently 20-years. Given the uncertainty of lease renewal and short expectations about the life of the equipment, a 20-year life proposal is reasonable for this account. There have been insufficient interim retirements to estimate an IR rate for this plant; consequently both the remaining life span and the average remaining life are 16 years for this account.

(7) Fuel Cells

SCE owns and operates two fuel cell demonstration facilities. The plants, located at California State University, San Bernardino (CSUSB) and University of California Santa Barbara (UCSB) were installed in September 2012 and October 2013 respectively. SCE is proposing to retain the currently authorized 10-year average service life. This proposal is consistent with our expectations that title to the demonstration facilities will be transferred to the site owners at the end of their 10-year lease.

(8) Energy Storage

The Commission has required SCE to procure and install 580 MW of energy storage facilities in its service territory by 2020. These facilities represent emerging technology and face significant risk of technological obsolescence in the future. SCE estimates the life of Energy Storage by the design life, cycle times of the proposed facilities, discussion with engineers, reviewing of reputable engineering studies and benchmarking with industry peers. SCE proposes a 10-year average service life for the Energy Storage and this represents a reasonable estimate of the expected life of these facilities when they are deployed.

b) Net Salvage Rates for Generation Assets

As discussed above, generation properties are retirement units that will retire in full at a specific time. Although there are interim additions and retirements that occur over the service life of the plant, the plant as a whole is subject to final retirement. SCE's generating plants—Palo Verde,

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[61] *Id.*

Hydro, Pebbly Beach, Mountainview, Peakers, Solar Photovoltaic, Fuel Cell—fit these characteristics. The net salvage for SCE's generation plants is considered using two basic elements—interim retirement net salvage and final retirement net salvage (*i.e.*, "decommissioning")—which are estimated separately. The final retirement net salvage entails an engineering estimate of the cost to remove and dispose of the plant and equipment existing at the time of the station's final shutdown.

In contrast to final retirements, interim retirement net salvage is the removal cost associated with the numerous small retirements occurring over the life of the generating station. This net salvage is estimated based upon an analysis of recorded interim net salvage ratios similar to the approach followed for mass property. Finally, the interim and final net salvage amounts are combined based upon the associated plant dollars to determine a total weighted average net salvage for the generating station. The estimated decommissioning costs at retirement are shown in the Table III-19 below. Interim retirement net salvage is relatively small with only a minor impact to amortization levels.

Table III-19
Generation Removal Cost

Plant	Decommissioning		Interim Retirement NS	
	Auth.	Prop.	Auth.	Prop.
A	B	C	D	E
Nuclear Production - Palo Verde	Covered Under NDCTP		-	$2.1 M
Hydro Production	-	-	$1.9 M	$4.5 M
Other Production				
Pebbly Beach	$6.6 M	-	-	-
Mountainview	$16.3 M	$16.2 M	-	-
Peakers	$12.1 M	$14.9 M	-	-
Solar Photovoltaic	$81.9 M	$80.8 M	-	-
Fuel Cells	-	-	-	-
Energy Storage	N/A	-	-	-

The net salvage estimates for generating stations will differ significantly depending upon a variety of factors. Although the net salvage consists of both interim retirement net salvage and final decommissioning costs, the scale of the decommissioning costs will generally drive the overall net salvage levels requested. In the case of Palo Verde, only interim retirement net salvage is included in the filing and is estimated to be zero percent at this time. The Commission will address the final decommissioning costs of Palo Verde in the Nuclear Decommissioning Cost Triennial Proceedings. The following sections discuss the decommissioning estimates for the respective generation facilities.

(1) Palo Verde Net Salvage

As previously mentioned, only interim retirements are addressed in this filing. While SCE did not request for interim retirement net salvage cost in its prior rate cases, recent retirement activity supports a modest increase. As such, SCE is proposing to include the interim retirement net salvage rates as shown in Table III-20, below.

Table III-20[62]
Palo Verde Interim Retirement Net Salvage

	Net Salvage Ratio (% of IRs)	Net Salvage Ratio (% of Plant)
Land and Land Rights	0.0%	0.0%
Structures and Improvements	-0.15%	0.0%
Reactor Plant Equipment	-20.0%	-3.7%
Turbogenerator Units	-16.0%	-5.9%
Accessory Electric Equipment	-13.0%	-0.6%
Misc. Power Plant Equipment	-16.0%	-2.0%

(2) Hydro Net Salvage

With the exception of San Gorgonio Unit 2, which is an active state of decommissioning, SCE is not requesting net salvage for decommissioning at this time. SCE is continuing to remove/retire San Gorgonio Unit 2 and is requesting $6.4M for the capital expenditures expected to be incurred from 2016 to 2019.

Interim retirement net salvage ratios for interim retirements are calculated by analyzing the recent retirement history for the level of net salvage incurred during interim retirements. The ratio of net salvage (gross salvage less cost of removal) divided by the retirement values is used to arrive at the net salvage ratios shown in Table III-21, below.

[62] Refer to WP SCE-09 Vol. 03, Book A, pp. 205-214 (Palo Verde Interim Retirements).

Table III-21[63]
Hydro Interim Retirement Net Salvage

	Net Salvage Ratio (% of IRs)	Net Salvage Ratio (% of Plant)
Structures and Improvements	-150%	-10.9%
Reservoirs, Dams and Waterways	-250%	-5.6%
Water Wheels, Turbines & Generators	-50%	-9.5%
Accessory Electric Equipment	-150%	-10.6%
Misc. Power Plant Equipment	-20%	-1.9%
Roads, Railroads & Bridges	-100%	-11.5%

(3) Pebbly Beach Net Salvage

Due to the expectations that the diesel generators will continue to operate in the foreseeable future, SCE is not proposing to recover any decommissioning costs in this rate case. Because of limited retirement history, SCE is not proposing recovery of interim retirement net salvage at this time.

(4) Mountainview Net Salvage

SCE compiled a list of equipment and facilities to be installed as part of the new generation facilities and itemized them by FERC plant account.[64] SCE then developed demolition costs for each component. The estimated decommissioning costs for Mountainview is $8.9 million (2012 dollars). SCE escalated the $8.9 million out to the end of the remaining life of the station, resulting in $16.2[65] million. Because of limited retirement history, SCE is not proposing recovery of interim retirement net salvage at this time.

(5) Peakers Net Salvage

In 2007, SCE commissioned Arcadis to perform decommissioning cost studies for each of its five Peaker units. Table III-22 below shows the current cost for each unit, totaling $7.7M. Escalated to the estimated year of final retirement produces a total future decommissioning cost of $14.9M.[66] Because of limited retirement history, SCE is not proposing recovery of interim retirement net salvage at this time.

[63] Refer to WP SCE-09 Vol. 03, Book A, pp. 215-223 (Hydro Interim Retirements).
[64] Refer to WP SCE-09 Vol. 03, Book A, pp. 308-313 (Mountainview Decomm).
[65] *Id.*
[66] Refer to WP SCE-09 Vol. 03, Book A, pp. 225-291 (Peakers Decomm).

Table III-22
Peaker Decommissioning Costs ($000's)

Line No.	Peaker Unit	2015 ($) Decomm	Retirement Year	Retirement Year Decomm ($)
1.	Barre	$1,427	2042	$2,676
2.	Center	$1,414	2042	$2,652
3.	Grapeland	$1,593	2042	$2,987
4.	McGrath	$1,683	2042	$3,155
5.	MiraLoma	$1,604	2047	$3,407
		$7,722		$14,877

(6) Solar Photovoltaic Net Salvage

In 2011, SCE commissioned Worley Parsons to conduct a decommissioning study of its Solar Photovoltaic Equipment. The study resulted in a range of estimates between $300,000 and $547,000 per megawatt in 2011 dollars based on the type of facility installed. Lower cost estimates are associated with ground mount installations characterized by ease of access and fewer equipment requirements, while the higher cost facilities are rooftop mounted that increase the complexity of removal activities. Escalating the estimates to the end of the proposed 20-year average service life results in a total decommissioning estimate of $81 million as shown in Table III-23. Because of limited retirement history, SCE is not proposing recovery of interim retirement net salvage at this time.

Table III-23
Solar Decommissioning Costs by Panel Type ($000's)

Installation Type	2015 $ Megawatt	Installed MW	Total Decomm 2015 ($)	Total Decomm Retirement Year ($)
A	B	C	D=B*C	E
Rooftop - Floating	$614	54	$32,890	$47,959
Rooftop - Anchored	$645	31	$20,071	$29,486
Ground Mount	$354	7	$2,395	$3,410
			$55,355	$80,855

(7) Fuel Cell Net Salvage

SCE is not proposing to recover decommissioning costs for Fuel Cells at this time because of the expectation to transfer ownership to site hosts at the end of their 10-year life.

While SCE is not proposing decommissioning at this time, it is not unreasonable to expect that if circumstances change, there will be future costs to retire these plants.

(8) Energy Storage Net Salvage

SCE is proposing to install lithium-ion battery units in a rack configuration. Engineers indicate that the removal activities to retire these assets include driving to the facility, removing the battery modules the rack, and shipping to recycling centers for disposal. Engineers also indicate that there may be a small amount of gross salvage associated with the recycling of the units. Although it is not unreasonable to assume that there may be increasing costs to retire these assets in the future (*e.g.*, if recycling salvage becomes disposal fees) SCE is not proposing decommissioning costs for energy storage assets at this time.

3. Forecast Service Lives for G&I Assets

Some categories of plant do not lend themselves to statistical analysis, but do not belong in the life span category. These plant assets include most general plant (*i.e.*, FERC Accounts 391-397), intangible plant (*e.g.,* software, radio frequencies, etc.), and easements. SCE determined average service lives through conducting discussions with SCE engineers familiar with the assets, considering prior company procedure, and being familiar with industry practice.

Table III-24, below, shows the forecast depreciation service lives for general and intangible plant accounts. The table compares SCE's proposed depreciation rates to authorized service lives from D.15-11-021 (the 2015 GRC Decision). As discussed in the sections below, because Power Management Systems (Account 391.4) and Telecommunications Equipment (Account 397) consist of sub-accounts of fairly disparate service lives, the subaccounts have been categorized based upon the equipment lives. For example, in the case of Telecommunication Equipment, SCE grouped Telephone Systems with Videoconferencing Equipment in a 7-year category separate from the infrastructure equipment such as open wire communication conductor and antenna support structures that belong in a 40-year category.

Table III-24[67]
General and Intangible Plant Service Life Proposals

Account No.	Account Description	2015-2017 Authorized (Years)	2018-2020 Proposed (Years)
General Plant			
391.1	Office Furniture	20	20
391.2	Personal Computers	5	5
391.3	Mainframe Computers	5	5
391.4	DDSMS-Power Management System	7.8	10.2
391.5	Office Equipment	5	5
391.6	Duplicating Equipment	5	5
391.7	PC Software	5	5
393	Stores Equipment	20	20
394	Tools & Work Equipment	10	10
395	Laboratory Equipment	15	15
397	Telecommunication Equipment	10.3	8.6
398	Misc Power Plant Equipment	20	20
Intangibles			
302.020	Hydro Relicensing	Various	Various
303.640	Radio Frequency	40	40
302.050	Miscellaneous Intangibles	20	20
303.105	Capitalized Software - 5 year	5	5
303.707	Capitalized Software - 7 year	7	7
303.210	Capitalized Software - 10 year	10	10
303.315	Capitalized Software - 15 year	15	15
Easements			
350	Transmission Easements	60	60
360	Distribution Easements	60	60
389	General Easements	60	60

[67] Refer to WP SCE-09 Vol. 03, Book A, pp. 5-12 (Rate Determination Schedule).

4. Forecast Service Lives – Account-By-Account

a) General Plant

Most general and intangible plant accounts contain many low value individual items. Following FERC guidelines, non-structural items in these accounts are amortized by vintage group over the specified service life and retired at the end of the life span.[68] For example, personal computers are amortized over a 5-year period (*i.e.*, a 20 percent annual depreciation rate) and when a vintage group reaches five years of age, the vintage group of computers will be fully depreciated and retired off the books. Following this approach eliminates costly plant record keeping and continuous physical tracking of the equipment. Over time, imbalances in the accumulated depreciation can occur if there are depreciation life or rate changes and if net salvage is recorded to the books but not reflected in the depreciation rate. These accumulated depreciation surpluses (deficits) are amortized over this GRC cycle (2018-2020).

(1) Account 391.1 – Office Furniture

Account 391.1 contains all costs incurred to acquire office furniture. It includes such items as modular furniture, desks, cabinets, and files used for general utility service that are not permanently attached to buildings. A 20-year average service life is reasonable for both modular and free standing furniture.

(2) Account 391.2 And 391.3 – Computer Equipment

The assets in Account 391.2 can include Central Processing Units and associated components (*e.g.*, monitors, printers, etc.) when purchased as a bundled unit, or when any of these items are purchased individually and meet the capitalization threshold. Account 391.3 is where SCE records all investment related to mainframe computer and file server equipment. SCE information technology personnel state that the average life for this equipment should be five years or less. Retention of the five-year life is reasonable.

(3) Account 391.4 – Power Management System

Account 391.4 contains Supervisory Control and Data Acquisition (SCADA) equipment for controlling and monitoring the SCE electrical system. Contained within this

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[68] FERC Accounting Release Number AR15 provided for the vintage year accounting method allowing companies to amortize vintage groups of assets over their designated service life and subsequently retire them. The FERC accounting release states that "[a]doption- of vintage year accounting will relieve companies from maintaining extensive plant records and will generate efficiencies and costs savings without degrading the quality of plant records and the associated financial reporting."

account are the components making up the Power Management System specifically, computer and data gathering equipment, man-machine interface, analog and digital telemetry devices, and data center facility infrastructure. The account consists of components with very different lives depending upon the technical sophistication and other retirement factors affecting the equipment. SCE's power management personnel have assessed this equipment as having service lives in categories of 5, 7, 10, 15 or 20 years. A dollar weighting of these equipment lives yields a combined average service life of about 10 years. Each of these equipment life categories are summarized in Table III-25 and addressed in the following discussions.

Table III-25
Power Management System Service Life Proposals

CPR Account	Description	2015-2017 Authorized (Years)	2018-2020 Proposed (Years)
Five-Year Power Management System Equipment			
391.417	Firewall	7	5
391.422	TACACS/Sniffer	10	5
391.405	EMS Web Server	20	5
391.406	EMS Workstation	20	5
391.43	External Tape Drive	20	5
Seven-Year Power Management System Equipment			
391.401	Bulk Storage	7	7
391.416	USAT Hub	7	7
Ten-Year Power Management System Equipment			
391.402	Communications Network Processor	10	10
391.404	Server Cabinet	10	10
391.411	Large Screen Display System	10	10
391.419	Dynamic Map Board	25	10
391.42	Data Acquisition Controller	10	10
391.429	Digital Wall Chart Recorded	10	10
391.435	Dial-Up Remote Terminal Unit	10	10
Fifteen-Year Power Management System Equipment			
391.436	Uninterruptible Power Supply	15	15
391.438	Battery System	15	15
Twenty-Year Power Management System Equipment			
391.421	Remote Terminal Unit (RTU)	20	20

(a) Five-Year Power Management System Equipment

Equipment in the 5-year category is typically modern, digital electronic computer and microprocessor-based equipment which is subject to discontinued support by the manufacturer or replaced with newer equipment within a short period of time. Due to these changing needs, the hardware asset portfolio will become obsolete if not actively refreshed, which can significantly affect operations. Furthermore, these devices contain components like processors, memory, and rotating disks that become obsolete and/or worn out after five years of continuous use.

(b) Seven-Year Power Management System Equipment

Equipment in the 7-year category is typically modern, digital electronic computer and microprocessor-based equipment which is subject to discontinued support by the manufacturer or replaced with newer equipment within a short period of time. Furthermore, these devices contain rotating disk, printers and CRTs that become obsolete and/or worn out after seven years of continuous use.

(c) Ten-Year Power Management System Equipment

SCE's power management personnel indicate that the ten-year lived equipment is less sophisticated than the typical 7-year items. They contain digital electronics as well as some electromechanical devices. Most of this equipment is specialized, proprietary and generally supported by the vendor for 10 years. Past experience indicates this equipment will be replaced after about 10 years.

(d) Fifteen-Year Power Management System Equipment

Telemetry equipment is analog devices with mostly repairable parts. They do not contain a high degree of sophistication and with proper maintenance, these devices should last approximately 15 years. The Uninterruptible Power System is an electromechanical device with a rated life of about 15 years. Beyond 15 years both of these devices require high levels of maintenance due to passive component failures and electromechanical malfunction.

(e) Twenty-Year Power Management System Equipment

Twenty-year power management system equipment contains hardened substation field equipment used for data gathering. The equipment is highly fault-tolerant and is typically supported by the vendor for approximately 20 years. Also included here are Wall Strip Chart Recorders and Backup Control Systems. These are robust analog devices containing some passive electronics typically rated for 20 years of service.

(4) Account 391.5 and 391.6 – Office Equipment; Duplicating Equipment

These accounts represent a $7.4 million net investment in miscellaneous office equipment such as video projection equipment, public address equipment, plotters, duplicating equipment, and so forth. The current service life of five years is reasonable.

(5) Account 393 – Stores Equipment

Account 393 represents a $7.6 million net investment in equipment used for the receiving, shipping, handling, and storage of materials and supplies for warehouses. It includes electric pallet jacks, lifting tables, stretch wrapping machine, racking rotobins/storage bins, battery chargers, transformer trays, hand-held scanners, lockers, picking carts, awnings, barrel grabbers, warehouse heaters, screen netting, cable cutting machines, and so forth. Based on historical Stores Equipment usage and knowledge of warehouse equipment, the operational personnel state that this equipment has a useful service life of 20 years or less. Retaining the current 20-year service life is reasonable for this account.

(6) Account 394 – Tools & Work Equipment

Account 394 represents a $49.2 million net investment in tools and equipment for construction, repair, maintenance, general shop, and garage, but not specifically includable in other accounts. SCE proposes retaining the current service life of 10 years.

(7) Account 395 – Laboratory Equipment

Account 395 represents a $63.8 million net investment in laboratory and field test equipment. The account has a wide variety of equipment. It includes, for example, calibrators, baths, furnaces, current shunts, dew point meters, gauge calibrators, insulation testers, gas leak detectors, mass comparator, micrometers, multimeters, oscilloscopes, phase meters, watthour meter testing power source, power system analyzers, self-contained portable calibration carts, sound meters, metrology standards, thermometer, vibration analysis data pack, and volt meters. The expected average service life of lab and test equipment is impacted by two major retirement factors: technological obsolescence and normal "wear and tear" from usage in both the field and lab environments. SCE proposes to retain the currently authorized 15-year average service life for this account.

(8) Account 397 – Telecommunication Equipment

Account 397 represents SCE's investment in communication equipment for the company's system. Contained within this account are the electronic and computer-based equipment (such as transmission equipment, dynamic network multiplexers, data network interconnection system, and radio equipment), as well as communication infrastructure (such as the copper and fiber optic cable, conduit, microwave equipment, and the electrical power generator system). SCE telecommunication engineers have assessed this equipment as having service lives of 5, 7, 10, 15, 25, or 40 years depending on the type of equipment.[69] These are the same service lives the Commission authorized in the prior rate case. The equipment lives are addressed in the following discussions.

(a) Five-Year Communication Equipment

Equipment falling into the 5-year category experiences shorter lives from lack of vendor support, facility relocations, and insufficient capacity to meet current demand.

(b) Seven-Year Communication Equipment

Equipment in the 7-year category is typically modern, state-of-the art, electronic and/or computer-based equipment which is subject to being discontinued by manufacturer or replaced with newer equipment within a short period of years.

(c) Ten-Year Communication Equipment

NetComm radio equipment is not as sophisticated as the other electronic equipment and warrants a 10-year service life. SCE is replacing NetComm radios after about 10 years.

(d) Fifteen-Year Communication Equipment

Equipment in this group of assets is typically subject to environmental wear and has an average life of about 15 years. The equipment fails or is replaced as a result of unreliability and/or high maintenance due to failure of passive components or electromechanical failure. In the case of electronic components included in this category, the telecommunication engineers state that these are relatively basic and not the state-of-the art- electronics reflected in the seven-year life category.

(e) Twenty-Five Year Communication Equipment

Although SCE has not yet had fiber optic cable as long as 25 years, SCE telecommunication engineers believe that it may be subject to greater level of degradation than the copper cable. They estimate that 25 years is a reasonable life for the fiber optic cable.

[69] Refer to WP SCE-09 Vol. 03, Book A, pp. 314-318 (Telecomm. Engineering Data).

(f) Forty-Year Communication Equipment

The balance of the communication infrastructure includes such equipment as overhead and underground communication cable, the communication conduit system, and antenna support structures. This equipment has an average 40-year service life. The items are subject to physical or mechanical deterioration since they are subject to outdoor environments.

(9) Account 398 – Miscellaneous

Account 398 represents a $21.8 million net investment in miscellaneous utility equipment that does not fit other plant accounts. Examples can include such diverse items as kitchen and infirmary equipment. The current service life of 20 years is a reasonable depreciation period for this account.

b) Intangibles

SCE has investments in a number of intangible assets, including hydro relicensing, radio frequencies, long term franchise fees, capitalized software, and land easements and rights-of-way. As previously discussed, the hydro relicensing costs are amortized over the remaining life of the FERC project license period. SCE proposes to continue amortizing the radio frequency investments over the 40-year service life and land easements and rights-of-way over the 60 year service life determined in prior rate case proceedings. The other categories are discussed below.

(1) Miscellaneous Intangibles

The year-end 2015 net investment for miscellaneous intangibles is approximately $431 thousand, which is largely made up of long-term franchise costs (~$300 thousand). SCE proposes to allocate these costs over 20 years.

(2) Capitalized Software

The depreciable life of capitalized software reflects the estimated life prior to investments required to replace or optimize the software as a result of technology, vendor, or business obsolescence. SCE proposes to continue the four existing service life categories of five, seven, ten, and fifteen years determined in prior proceedings.

(3) Easements

SCE proposes to retain the authorized amortization period of 60 years for its easements and rights-of-way.

Appendix A

2016 Service-Life and Net Salvage Study

2016
Service–life and Net Salvage Study

SOUTHERN CALIFORNIA EDISON

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CONTENTS

EXECUTIVE SUMMARY

INTRODUCTION

This report presents a study and recommended service–life statistics and future net salvage rates for transmission, distribution and general depreciable plant owned and operated by Southern California Edison Company (SCE). Foster Associates was engaged by SCE in January 2016. The study was completed in July, 2016.

Foster Associates is a public utility economics consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by SCE were approved by the California Public Utilities Commission (CPUC) in D.15–11–021, dated November 5, 2015. The approved rates were derived from a study conducted on December 31, 2012 plant and depreciation reserve balances. Findings and recommendations developed in the current study are summarized in Section III of this report.

SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Field visits and discussions with SCE operations and plant accounting personnel;
- Statistical life studies and estimation of projection lives and projection curves; and
- Per unit and moving average net salvage studies and estimation of future net salvage rates.

STUDY PROCEDURE

INTRODUCTION

The purpose of a comprehensive depreciation study for a regulated utility is to analyze the mortality characteristics, net salvage rates and the adequacy of depreciation accruals derived from currently approved depreciation rates. The findings from such an investigation are used in the formulation of revised depreciation rates subject to regulatory approvals.

In the case of the current study, Foster Associates was engaged by SCE to only study and recommend service–life statistics and future net salvage rates in compliance with CPUC directives in D.15–11–021. SCE would then incorporate the recommendations in depreciation rates developed by the Company.

Regarding the directives in D.15–11–021, the CPUC directed SCE to provide full explanations of the quantitative or qualitative base for the application of judgment in future depreciation showings. The Commission further directed the Company to provide:

1. A quantitative discussion of historical and future COR on a per unit basis for the large (greater than 15% as measured by the portion of plant balance) asset classes in the account. This should identify and explain the key factors in changing or maintaining the per–unit COR.
2. Quantitative discussion of historical and future retirement mix; identifying and explaining the key factors in changing or maintaining this mix.
3. Quantitative discussion of asset life and original cost of assets being retired, in relation to the COR, on both a historical and prospective basis. This discussion should be integrated with and/or cross–reference the proposal for life characteristics.
4. An account–specific discussion of the process for allocating costs to COR.

SCOPE

The steps involved in conducting the depreciation study can be grouped into three major tasks:

- Data Collection;
- Life Analysis and Estimation; and
- Net Salvage Analysis and Estimation.

The scope of the 2016 service–life and net salvage study included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by SCE provides aged transactions for all plant accounts.

Service life statistics estimated in the 2016 study were derived from plant accounting transactions recorded over the period 2002 through 2015. Detailed accounting transactions were extracted from the Continuing Property Record (CPR) system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

The accuracy and completeness of the assembled database was verified for activity years 2002 through 2015 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Age distributions of surviving plant at December 31, 2015 were reconciled to the CPR.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

It is important to note what is being estimated in a service life study. It is not unit-years of service; it is dollar–years of service. Retirements are not recorded for plant accounting purposes in units such as feet, pounds, segments or any similar physical measurement. Plant records are maintained in dollars and service lives are measured in dollar–years of service. Estimating service lives based on engineering studies of how long, on average, units of property might remain in service is not equivalent to estimating dollar–years of service.

The size of a retirement unit also matters. A company that defines a span of conductor between supports to be a retirement unit will measure longer service lives than a company that defines one foot of conductor as a retirement unit. Replacement of conductor less than a retirement unit is charged to operating expense and no retirement is recorded for the replaced unit. Larger units result in less frequent recorded retirements, which translate to longer average dollar–years of service.

An added dimension of complexity is introduced when retirements occur at varying ages, attributable to mixed forces of retirement. This creates a non-homogeneous account composed of two subpopulations acted upon by differing forces of retirement. The estimated projection life for such an account measured in dollar–years of service will converge toward the mean of the subpopulation most resistant to the forces of retirement.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements over the period 2002–2015 was available for all plant accounts included in the 2016 study.

An actuarial life analysis program designed and developed by Foster Associates was used in this study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called "retirement ratio" (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves which are mathematically described by the Pearson frequency curve family. Observed life tables were smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function was expressed as a survivorship function and numerically integrated to obtain an estimate of the projection life for each plant account. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the Foster Associates actuarial life analysis program include: the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, poles and conductors), the concept of retirement dispersion is interpreted differently for plant categories composed of major items of plant that will most likely be retired as a single unit. Plant retirements from an integrated system prior to the retirement of the entire facility are more properly viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Additionally, plant facilities may be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span method. All depreciable plant accounts classified in transmission, distribution and general were studied as full mortality categories in the 2016 study.

Net Salvage Analysis

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a reasonable basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are: the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Average net salvage rates for an account or plant function are derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements *(i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions alter the weighting of future net salvage estimates.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was conducted in the 2016 study for transmission, distribution and general plant categories to aid in: a) estimating a realized net salvage rate; b) detecting the emergence of historical trends; and c) establishing a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were also considered in the estimation of future net salvage rates.

In compliance with the CPUC directive in D.15–11–021, per unit net salvage analyses were conducted for the nine (9) plant accounts listed in Table 1 below.

Account Description
354.00 Towers and Fixtures
355.00 Poles and Fixtures
356.00 Overhead Conductors and Devices
364.00 Poles, Towers and Fixtures
365.00 Overhead Conductors and Devices
366.00 Underground Conduit
367.00 Underground Conductors and Devices
368.00 Line Transformers
369.00 Services

Table 1. Per Unit Net Salvage Accounts

Each of the nine plant accounts was grouped into one or more subpopulations of major equipment categories. Historical per unit ratios (defined as net cost per unit to retire divided by the cost per unit to install) were used in both a historical and future per unit analyses. Net costs to retire (or net salvage) were used in the analysis to maintain consistency with future net salvage parameters used in the formulation of remaining–life accrual rates.

Future per unit ratios were derived using an average of the subpopulation net salvage per unit values recorded over the period 2009–2015. These values appear in the numerator of future per unit ratios.

The per unit cost of plant additions used in forecasting future net salvage rates was obtained by dividing vintaged plant in service at December 31, 2015 (*i.e.*, age distributions of surviving plant) by vintaged units in service within each subpopulation. The ratio of average net salvage per unit experienced over the period 2009–2015 (adjusted for inflation) to the per unit cost of plant in service is the ratio that was applied to forecasted retirements to estimate future net salvage for each vintage. The sum of future net salvage over all vintages divided by current plant account balances produces an estimated future net salvage rate for each primary account.

RECOMMENDATIONS AND ANALYSIS

RECOMMENDATIONS

Table 2 below provides a summary of current and recommended projection lives, projection curves and future net salvage rates estimated for SCE in the 2016 study.

Account Description	Current			Recommended		
	P-Life	Dispersion	Sf %	P-Life	Dispersion	Sf %
A	C	D	E	F	G	H
Transmission Plant						
352.00 Structures and Improvements	55.00	S3	-35.0	55.00	L1	-35.0
353.00 Station Equipment	45.00	R0.5	-15.0	40.00	L0.5	-10.0
354.00 Towers and Fixtures	65.00	R5	-60.0	65.00	R5	-185.0
355.00 Poles and Fixtures	50.00	R0.5	-72.0	65.00	SC	-499.0
356.00 Overhead Conductors and Devices	61.00	R3	-80.0	61.00	R3	-210.0
357.00 Underground Conduit	55.00	R3	0.0	55.00	R3	0.0
358.00 Underground Conductors and Devices	40.00	R2.5	-15.0	45.00	S1	-25.0
359.00 Roads and Trails	60.00	SQ	0.0	60.00	R5	0.0
Distribution Plant						
361.00 Structures and Improvements	42.00	R2.5	-25.0	50.00	L0.5	-30.0
362.00 Station Equipment	45.00	R1.5	-25.0	65.00	L0.5	-50.0
364.00 Poles, Towers and Fixtures	47.00	L0.5	-210.0	55.00	R1	-488.0
365.00 Overhead Conductors and Devices	45.00	R0.5	-115.0	55.00	R0.5	-538.0
366.00 Underground Conduit	59.00	R3	-30.0	59.00	R3	-401.0
367.00 Underground Conductors and Devices	45.00	R0.5	-60.0	43.00	R1.5	-261.0
368.00 Line Transformers	33.00	R1	-20.0	33.00	S1.5	-47.0
369.00 Services	45.00	R1.5	-100.0	45.00	R1.5	-387.0
370.00 Meters	20.00	R3	-5.0	20.00	R3	0.0
373.00 Street Lighting and Signal Systems	40.00	L0.5	-30.0	48.00	L1	-100.0
General Plant						
390.00 Structures and Improvements	38.00	R3	-5.0	45.00	R0.5	-10.0

Table 2. Service Life and Net Salvage Parameters

ANALYSIS

A description of each account examined in the 2016 study and factors considered in the estimation of recommended service life and net salvage parameters is contained in the following pages of this report.

TRANSMISSION PLANT
ACCOUNT: 352.00 – STRUCTURES AND IMPROVEMENTS

DESCRIPTION

This account includes the cost in structures and improvements used in connection with transmission operations. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	55-S3	55-L1
Future NS Rate	-35.0%	-35.0%
Realized NS	-13.3%	
Average Age (yrs.)	8.6	
Derived Additions	$717,577,812	
Plant Retirements	$30,750,408	
Percent Retired	4.5%	
Plant Balance	$686,827,404	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Major forces of retirement for this account include system upgrades, severe storms and earthquakes, traffic and fire accidents, rodent damage, automation, revisions in policy, code, and criteria, and wear and tear related to aging.

The statistical service life indications for the full account are derived from unlikely recurring retirement activity. Retirements of $22.9M reported in 2009, constituting 75 percent of the total retirements over the 14–year study period, were related to the retirement of equipment at the Sylmar substation. Average service life indications from the statistical service life analysis range from the low 30s to the mid–50s for bands with lower censoring and conformance indexes. The majority of second– and third–degree polynomial indications are considered less reliable than first–degree polynomial indications. Graduated hazard rates in these instances are unrealistically declining and may be zeroed to remove negative hazard rates implied by the fitted polynomials.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each subpopulation are shown in Table 2 below.

The variability of subpopulation service lives is an indication of a nonhomogeneous plant account with mixed forces of retirement acting on the subpopulations. Heterogeneity coupled with high degrees of censoring reduces the level of confidence that can be placed in service–life indications obtained from either a subpopulation or total account analysis.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Foundations	178,220,072	26	85-L1	38.5
MEER Building	159,486,338	23	130-R0.5	73.4
Water Supply	107,675,420	16	103-R3	82.8
Alarm & Monitoring	45,931,434	7	194-S6	99.4
Power Lighting	30,490,714	4	107-L0.5	71.9
HVAC	12,046,998	2	38-L0	7.7
Non-unitized	120,611,640	18		
Miscellaneous	32,364,788	5	30-L0.5	3.7
Total	686,827,404	100	107	

Table 2. Major Structural Components

LIFE ESTIMATION

Based mainly on the first–degree statistical service–life indications, thereby rejecting origin–modal dispersions in which chance is a more pervasive force of retirement, a 55–L1 projection life–curve is recommended for this account. This recommendation retains the currently approved projection life and adjusts the projection curve to reflect lower modal curves observed in the subpopulation analysis. The recommendation also reflects a lack of evidence for adjusting the service life estimates given the single retirement underlying a significant percentage of the retirement history. Foster Associates was informed that Company engineers and operations personnel do not anticipate policy or procedural changes or technological advances that would introduce significantly different forces of retirement from those observed in the past.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account exhibits an overall realized net salvage rate of –13.3 percent from $31M of retirement activity over the period 2002–2015. More recent 5–year moving average bands indicate realized negative net salvage exceeding –87 percent.

NET SALVAGE ESTIMATION

Based on this historical experience and the expectation of continuing removal costs when these facilities are retired, retention of a –35 percent future net salvage rate is recommended for consideration by SCE. As in the service life estimation, this recommendation reflects lack of evidence for adjusting future net salvage estimates given the single retirement underlying a significant percentage of the retirement history in this account.

TRANSMISSION PLANT
ACCOUNT: 353.00 – STATION EQUIPMENT

DESCRIPTION

This account includes the cost in transforming, conversion, and switching equipment used for the purpose of changing the characteristics of electricity in connection with its transmission or for controlling transmission circuits. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R0.5	40-L0.5
Future NS Rate	-15.0%	-10.0%
Realized NS	0.6%	
Average Age (yrs.)	10.3	
Derived Additions	$5,785,827,668	
Plant Retirements	$538,115,861	
Percent Retired	10.3%	
Plant Balance	$5,247,711,807	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Retirement activity in transmission station equipment is largely associated with age, obsolescence and growing or shifting loads that necessitate rebuilding to larger capacities. Company engineers report that thermal, mechanical, and electrical integrity issues intensify with age typically beginning around age 30 years when insulation degradation, increased in–service failures, and increased maintenance arises. Retirements occur when increased costs and decreased utilization rates dictate is it no longer economic to repair such equipment. Decreased spare parts availability as equipment ages also plays a major role in age–related retirements.

The Company utilizes a Condition Based Maintenance (CBM) approach to manage all transformers and circuit breakers by routinely conducting off–line diagnostics, visual inspections, and functional checks. These analysis components are combined with other key data such as age, design, moisture levels, loading, and fault exposure to develop a health index ranking that is maintained throughout the life of these assets and used in the determination of when to repair or retire.

Average service life indications from the statistical analysis of the full account range from the low 30s to the low–40s for bands with lower censoring and conformance indexes. The majority of second– and third–degree polynomial indications are considered less reliable than first–degree polynomial indications. Graduated hazard rates in these instances are unrealistically declining and may be zeroed to remove negative hazard rates implied by the fitted polynomials.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	Investment %	Full Band PLife-Curve	Censoring (%)
Transformers	1,068,594,714	20	41-SC	7.6
Circuit Breakers	631,804,488	12	32-L1.5	0.8
Switches & Switch Gear	520,013,661	10	34-L0	10.4
Control & Monitoring Devices	478,204,337	9	50-L0	-
Bus Support Structures	439,776,382	8	63-R0.5	27.5
Capacitors	309,258,912	6	49-L1	0.6
Power Control Cable	267,340,154	5	51-SC	30.6
Foundations	151,926,940	3	70-L1	34.5
Non-unitized	790,758,849	15		
Miscellaneous	590,033,371	11	36-L0.5	11.2
Total	5,247,711,807	100	44	

Table 2. Major Structural Components

The subpopulation analysis of the full historical experience exhibits a range of average service lives between 32 and 63 years with a direct–dollar–weighted average of 44 years and a preponderance of lower–left modal dispersions. Service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of these subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

LIFE ESTIMATION

Based on indications from both the full account and subpopulation statistical service life analyses, a 40–L0 projection life–curve is recommended for this account. This recommendation is derived from account total service lives indicated for trials with lower censoring, conformance indexes, and hazard functions uncompromised by declining or negative hazard rates. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –12.7 percent, a composite of an 8.2 percent gross salvage rate and a 20.9 percent cost of retiring rate. The most recent 5–year rolling average indicates a –26.4 percent realized net salvage rate.

Net Salvage Estimation

Minimal gross salvage, generally from scrap metal and recycling, is expected from the retirement of this equipment. Significant cost of retiring, however, is expected in the form of labor and equipment such as cranes. The adjusted historical net salvage experience provides the basis for recommending a –10 percent future net salvage rate for consideration by SCE. This recommendation reflects discounting indications obtained from small retirements and large cost of removal recorded in 2015 and focusing more on activity years 2009−2014. The –12.7 realized net salvage rate and –26.4 percent realized net salvage rate observed for the most recent 5–year rolling band are somewhat distorted by the 2015 activity, which is not considered indicative of future expectations.

TRANSMISSION PLANT
ACCOUNT: 354.00 – TOWERS AND FIXTURES

DESCRIPTION

This account includes the cost installed of towers and appurtenant fixtures used for supporting overhead transmission conductors. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	65-R5	65-R5
Future NS Rate	-60.0%	-185.0%
Realized NS	-799.7%	
Average Age (yrs.)	9.3	
Derived Additions	$2,264,446,057	
Plant Retirements	$4,473,231	
Percent Retired	0.2%	
Plant Balance	$2,259,972,826	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Forces of retirement acting upon transmission towers and fixtures include line upgrades, corrosion, relocation (for lower voltage structures), and failures due to wind storms, ice, or floods. Most of these forces tend to increase with age. Although storm damage can generally be expected to impact retirements at any age, in combination with deterioration, the probability of failure is cumulative. SCE performs annual inspections on all transmission towers and performs subsequent maintenance identified from those inspections.

The statistical service life indications for the full account are derived from minimal and irregular retirement activity. Retirements recorded in this account amount to only $4.5M from an average plant balance exceeding $1.3B over the study period and less than 0.2 percent of derived additions. Statistical service life indications derived from this minimal experience are highly censored, unrealistically long (approaching 200 years), and contrary to Company expectations of the future age of tower retirements.

The distribution of major categories of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Towers	1,139,621,027	50	132-S2	71.6
Non-unitized	1,018,898,065	45		
Other	101,453,734	4	178-R2.5	82.2
Total	2,259,972,826	100	136	

Table 2. Major Structural Components

The subpopulation analysis is also highly censored and does not produce interpretative life indications. The account could not be reasonably sub–divided into more than three subpopulations with miscellaneous items constituting only four percent and non–unitized items constituting 45 percent of the investment.

Life Estimation

The minimal retirement activity and resulting unreliable service life indications from both the full account and subpopulation statistical analyses do not provide a strong foundation for service–life estimation. Foster Associates, therefore, deferred to SCE in recommending the currently approved 65–R5 projection life–curve. Factors evaluated by SCE beyond the service–life analyses include operational, accounting and ratemaking considerations.

Net Salvage Analysis

The adjusted net salvage analysis for this account indicates an overall net salvage rate of –799.7 percent realized from $4.5M of retirements recorded over the period 2002–2015. However, as noted above, total retirements are less than 0.2% of derived additions.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –104 and –185 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

Net Salvage Estimation

Although minimal gross salvage, generally from scrap, is expected from these assets, significant costs of retiring and removing (attributable to labor costs and cost of equipment such as cranes used in the retirement process) are expected to be incurred in the future. Based on the above analysis, a future net salvage rate of −185 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

TRANSMISSION PLANT
ACCOUNT: 355.00 – POLES AND FIXTURES

DESCRIPTION

This account includes the installed cost of transmission line poles, wood, steel, concrete, or other material, together with appurtenant fixtures used for supporting overhead transmission conductors. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	50-R0.5	65-SC
Future NS Rate	-72.0%	-499.0%
Realized NS	-155.5%	
Average Age (yrs.)	10.1	
Derived Additions	$1,073,636,145	
Plant Retirements	$65,068,786	
Percent Retired	6.5%	
Plant Balance	$1,008,567,359	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The majority of wood poles in the Company's system are full–length and "through–boring" treated to protect against decay and insect attack. Wood poles may also be treated with a steel stub or a fiberglass wrap to provide additional support. In addition to pole treatment, the Company conducts a 10–year inspection cycle to address safety and reliability. Tree trimming and vegetation management are also a significant component of reliability measures undertaken by the Company.

Major forces of retirement acting upon transmission wood poles include external, internal, top rot, and split top deterioration. Additional forces include vehicles, wind, storm, fire, and bird (mainly woodpecker) damage. Response to these forces partly depends on the specific locale of the pole given the Company's wide geographical area encompassing mainly desert but also agricultural, rural, and urban communities.

Indications from the statistical service life analysis for this account range from the mid–60s to the low–80s for bands with lower censoring and conformance indexes. The majority of third–degree polynomial indications are considered less reliable than first–degree or second–degree polynomial indications. Graduated hazard rates in these instances are unrealistically declining and may be zeroed to remove negative hazard rates implied by the fitted polynomials.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Eng. Light Duty Steel, Concrete	419,049,403	42	84-L0.5	57.2
Wood/Fiberglass/Composite	375,781,560	37	57-SC	29.6
Non-Unitized	212,474,639	21		
Other	1,261,756	0	46-S4	53.5
Total	1,008,567,359	100	71	

Table 2. Major Structural Components

The subpopulation analysis indicates service lives ranging between 46 and 84 years with an average of 71 years. It is the opinion of Foster Associates that service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, non–homogeneous plant category.

LIFE ESTIMATION

Based on the first–degree and second–degree indications of the full account analysis and observations from the subpopulation analysis, a 65–SC projection life–curve is recommended for this account. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall realized net salvage rate of –155.5 percent and a –242.5 percent rate for the most recent five–year rolling band. Five–year rolling bands indicate negative net salvage rates exceeding –100 percent for 8 of the 11 analyzed bands.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –90 and –499 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −499 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

TRANSMISSION PLANT
ACCOUNT: 356.00 – OVERHEAD CONDUCTORS AND DEVICES

DESCRIPTION

This account includes the installed cost of overhead conductors and devices used for transmission purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	61-R3	61-R3
Future NS Rate	-80.0%	-210.0%
Realized NS	-284.3%	
Average Age (yrs.)	13.7	
Derived Additions	$1,500,210,639	
Plant Retirements	$18,103,015	
Percent Retired	1.2%	
Plant Balance	$1,482,107,624	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Forces of retirement acting upon transmission conductors include deterioration resulting from atmospheric corrosion, fatigue failure due to conductor vibration, storm damage, failure of splices or dead–ends, relocation (*e.g.*, highway widening, damsite construction, etc.), circuit upgrades, system reconfiguration and idle facilities (*e.g.*, closure of generation facilities or loss of large customers).

The statistical service life analysis for this account indicates average service lives exceeding 85 years. The analysis, however, is based on $18M of retirement activity from derived additions exceeding $1.5B. Retirement activity of 1.2 percent of derived additions is not considered sufficient to provide a reliable basis for service life estimation.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 is shown in Table 2. More than 40 percent of the classified investment is conductor larger than 1500 MCM. Service life indications obtained from a full–band statistical analysis of the major categories are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Conductor > 220 kV	739,015,019	50	106-R3	57.7
Conductor < 220 kV	202,769,129	14	82-R1.5	84.0
Switches	27,761,688	2	39-R1	2.5
Non-Unitized	399,410,246	27		
Other	113,151,541	8	199-SQ	100.0
Total	1,482,107,623	100	110	

Table 2. Major Structural Components

The subpopulation analysis of the full historical experience evidences a range of average service lives between 39 and 199 years with a dollar–weighted average of 110 years. These indications are compromised by high censoring and minimal retirement activity comparable to observations in the full account.

LIFE ESTIMATION

With consideration given to the minimal retirement experience in this account and the resulting extremes in service life indications, Foster Associates deferred to the Company in recommending retention of the currently approved 61–R3 projection service–life parameters.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –284.3 percent. However, as noted above, this history is based on relatively minimal retirement activity over the period 2002–2015.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –114 and –210 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −210 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

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TRANSMISSION PLANT
ACCOUNT: 357.00 – UNDERGROUND CONDUIT

DESCRIPTION

This account includes the installed cost of underground conduit and tunnels used for housing transmission cables or wires. Account statistics and current and proposed parameters are shown in Table 1.

	Current	Proposed
Plife-Curve	55-R3	55-R3
Future NS Rate	0.0%	0.0%
Realized NS	-69.5%	
Average Age (yrs.)	15.6	
Derived Additions	$61,474,359	
Plant Retirements	$387,297	
Percent Retired	0.6%	
Plant Balance	$61,087,062	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Rebuild and digging are the major forces of retirement expected to affect this account. The statistical service–life analysis for the full account is based on highly censored trials (87 percent) with life indications ranging between 88 and 146 years. Only $387,297 or 0.6% of derived additions has been retired from the account.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Conduit	34,334,761	56	130-S1.5	86.3
Manholes and Vaults	17,239,213	28	65-S2	81.1
Trenches	2,063,079	3		N/A
Non-unitized	7,410,219	12		
Other	39,791	0		N/A
Total	61,087,062	100	108	

Table 2. Major Structural Components

full–band statistical analysis of each category are shown in Table 2 below.

Subpopulation service life indications are similarly derived from highly censored trials providing little insight into future live expectancies.

Life Estimation

Neither the full account nor the subpopulation analysis is considered to provide sufficient evidence to support adjusting the currently approved 55–R3 projection life and curve. Current parameters are, therefore, recommended to be retained for this account.

Net Salvage Analysis

The adjusted net salvage analysis for this account indicates an overall net salvage rate of –69.5% percent realized from minimal retirement activity of only $387,297.

Net Salvage Estimation

The historical net salvage experience is considered insufficient to support an adjustment to the currently approved zero percent future net salvage rate. The current rate is, therefore, recommended for consideration by SCE.

TRANSMISSION PLANT
ACCOUNT: 358.00 – UNDERGROUND CONDUCTORS AND DEVICES

DESCRIPTION

This account includes the installed cost of underground conductors and devices used for transmission purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	40-R2.5	45-S1
Future NS Rate	-15.0%	-25.0%
Realized NS	-27.0%	
Average Age (yrs.)	11.6	
Derived Additions	$284,995,149	
Plant Retirements	$16,382,826	
Percent Retired	6.1%	
Plant Balance	$268,612,323	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Deterioration, failure, relocations, upgrades and accidental dig–ins are the major forces of retirement acting upon underground conductors. The statistical life analysis conducted for this account indicates average service lives between the mid–30s and mid–40s for trials with lower censoring, conformance indexes, and non–negative retirement ratios.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Conductor	163,955,728	61	45-S1.5	51.1
Potheads	27,568,689	10	29-S2	5.2
Arresters	19,845,390	7	31-S1.5	2.0
Cathodic Protection	12,086,839	4	39-R1	81.4
Non-unitized	45,155,677	17		
Total	268,612,323	100	41	

Table 2. Major Structural Components

An analysis of the subpopulations indicates a range of service lives between 29 and 45 years with lower modal dispersions and an average of 41 years. Service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

LIFE ESTIMATION

Based on these observations and considerations, a 45–S1 projection life–curve is recommended for this account. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –27 percent realized from $16M of retirement activity over the period 2002–2015. Five–year rolling bands are relatively stable and range between –14.4 and –49.7 percent. The most recent 5–year rolling band indicates a realized average net salvage rate of –30.6 percent.

NET SALVAGE ESTIMATION

Based on the analysis observations, a –25 percent future net salvage rate is recommended for consideration by SCE. Consideration was given in this recommendation to both the –27 historical average realized net salvage rate and the likelihood of more negative future net salvage given recent experience such as the –30.6 percent realized net salvage rate observed for the most recent 5–year rolling band.

Transmission Plant
Account: 359.00 – Roads and Trails

Description

This account includes the cost of roads, trails, and bridges used primarily as transmission facilities. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	60-SQ	60-R5
Future NS Rate	0.0%	0.0%
Realized NS	-314.1%	
Average Age (yrs.)	5.1	
Derived Additions	$194,172,555	
Plant Retirements	$154,514	
Percent Retired	0.1%	
Plant Balance	$194,018,041	

Table 1. Account Parameters and Statistics

Life Analysis

The statistical service life analysis for this account is based on minimal retirement activity of $154,514, or 0.1 percent of derived additions from an average plant balance exceeding $108M over the period 2002–2015. Retirements were reported in only 3 years during that period. The service life analysis is highly censored at more than 76.8 percent with resulting life indications ranging between 95 and 175 years.

Life Estimation

Statistical service life indications for this account are considered insufficient to warrant an adjustment to the currently approved projection life. The current SQ projection curve, however, is considered extreme given the historical experience and the likelihood of more dispersed retirements. Based on these observations and considerations, a 60–R5 projection life–curve is recommended for this account.

Net Salvage Analysis

The adjusted historical net salvage analysis for this account indicates a realized net salvage rate of –314.1 percent from retirements recorded in 2010, 2012, and 2013 only.

Net Salvage Estimation

The underlying retirement experience in the historical net salvage analysis is not considered sufficient to warrant adjusting the currently approved zero percent future net salvage. Retention of the current rate is, therefore, recommended for consideration by SCE.

Distribution Plant
Account: 361.00 – Structures and Improvements

Description

This account includes the cost in place of structures and improvements used in connection with distribution operations. The account comprises mainly control houses and related structures at distributions substations. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	42-R2.5	50-L0.5
Future NS Rate	-25.0%	-30.0%
Realized NS	-33.1%	
Average Age (yrs.)	13.8	
Derived Additions	$632,396,471	
Plant Retirements	$55,690,492	
Percent Retired	9.7%	
Plant Balance	$576,705,979	

Table 1. Account Parameters and Statistics

Life Analysis

Major forces of retirement for this account include system upgrades, severe storms and earthquakes, traffic and fire accidents, rodent damage, automation, revisions in policy, code, and criteria, and wear and tear related to aging.

Statistical service life indications for this account range from the low–40s to low–60s for bands with lower censoring and conformance indexes. The majority of second and third–degree polynomial indications are considered less reliable than first–degree polynomial indications. Graduated hazard rates in these instances are unrealistically declining and may be zeroed to remove negative hazard rates implied by the fitted polynomials.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Foundation etc.	112,919,451	20	28-S4	76.6
MEER Building	102,746,634	18	38-S1.5	80.8
Water Supply	50,908,790	9	41-S1.5	74.6
Power Lighting	45,421,111	8	39-S3	92.0
HVAC	33,804,236	6	35-R2	72.5
Alarm & Monitoring	16,557,229	3	29-S3	84.1
Non-unitized	39,863,694	7		
Other	174,484,836	30	60-O3	29.4
Total	576,705,980	100	43	

Table 2. Major Structural Components

An analysis of the subpopulations indicates average service lives ranging between 29 and 60 years, various dispersions, and a dollar–weighted mean of 43 years.

Life Estimation

Based on these observations and ignoring origin–modal dispersions in which chance is a more pervasive force of retirement, a 50–L0.5 projection life–curve is recommended for this account.

Service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category. Company operations personnel do not expect policy or procedural changes or technological advances that would introduce significantly different forces of retirement from those observed in the past.

Net Salvage Analysis

The historical net salvage analysis for this account indicates an adjusted overall net salvage rate of –33.1 percent realized from $55,690,492 of retirement activity over the period 2002–2015. Five–year rolling band rates have not been less negative than –21.3 percent during that period and the five–year band ending in in 2015 shows a –44.2 percent net salvage rate.

Net Salvage Estimation

Based on these observations and considerations, a –30 percent future net salvage rate is recommended for consideration by SCE. It is considered unlikely that the upward trend in cost of removal will reverse in the near future.

DISTRIBUTION PLANT
ACCOUNT: 362.00 – STATION EQUIPMENT

DESCRIPTION

This account includes the installed cost of station equipment, including transformer banks, used for the purpose of changing the characteristics of electricity in connection with its distribution. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R1.5	65-L0.5
Future NS Rate	-25.0%	-50.0%
Realized NS	-46.5%	
Average Age (yrs.)	13.1	
Derived Additions	$2,382,404,227	
Plant Retirements	$138,133,698	
Percent Retired	6.2%	
Plant Balance	$2,244,270,529	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The statistical service life analysis for this account indicates average service lives within a narrow range between the mid–50s and mid–60s for bands with lower censoring and conformance indexes.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Transformers	359,814,116	16	56-L1	81.9
Monitoring Devices	275,879,081	12	34-R2	61.6
Circuit Breakers	270,107,330	12	45-S0.5	81.3
Bus Support	182,345,026	8	75-L0.5	90.1
Power Control Cable	115,539,624	5	42-L1	75.7
Switches	95,098,077	4	52-L1	81.7
Non-unitized	394,553,141	18		
Other	550,934,134	25	64-L0.5	19.7
Total	2,244,270,528	100	54	

Table 2. Major Structural Components

An analysis of the subpopulations indicates average service lives between 34 and 75 years with lower modal dispersions and a dollar–weighted mean of 54 years.

Service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

LIFE ESTIMATION

Based on these observations and considerations, a 65–L0.5 projection life–curve is recommended for this account. This recommendation is within the range of both full account and subpopulation service life indications. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

Although not equivalent to dollar–years of service, SCE engineers estimate a mean time to wear–out of about 37 years for A–Bank (200 kV) transformers and about 57 years for B–Bank (115 or 66 kV) transformers. The number of transformers in service at year–end 2015 was 158 A–Bank and 2,226 B–Bank. Company engineers also estimate that the mean time to wear–out of mainline and radial oil switches is about 35 years and about 49 years for circuit breakers. The average age of transformers measured in unit−years is about 26 years whereas the average age measured in dollar–years is about 10 years. Similarly, the average age of circuit breakers measured in unit−years is about 32 years whereas the average age measured in dollar–years is about 10 years.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –46.5 percent, realized from $138,133,698 of retirement activity and 5.8 percent of derived addition over the period 2002–2015. Most recent 5–year rolling bands ending in 2013, 2014,and 2015 exhibit net salvage rates of –47.2, –65.6 and –81.4 percent respectively.

NET SALVAGE ESTIMATION

Based on these observations and the expectation of continuing negative net salvage, a –50 percent future net salvage rate is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 364.00 – POLES, TOWERS AND FIXTURES

DESCRIPTION

This account includes the installed cost of poles, towers, and related fixtures used for supporting overhead distribution conductors and service wires. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	47-L0.5	55-R1
Future NS Rate	-210.0%	-488.0%
Realized NS	-505.0%	
Average Age (yrs.)	11.3	
Derived Additions	$2,608,099,972	
Plant Retirements	$144,713,616	
Percent Retired	5.9%	
Plant Balance	$2,463,386,356	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The majority of wood poles in the Company's system are full–length and "through–boring" treated to protect against decay and insect attack. Wood poles may also be treated with a steel stub or a fiberglass wrap to provide additional support. In addition to pole treatment, the Company conducts a 10–year inspection cycle to address safety and reliability. Tree trimming and vegetation management are also a significant component of reliability measures undertaken by the Company.

As with transmission wood poles, major forces of retirement acting upon distribution wood poles include external, internal, top rot, split top deterioration and pole loading. Additional forces include vehicles, wind, storm, fire, and bird (mainly woodpecker) damage. Response to these forces partly depends on the specific locale of the pole given the Company's wide geographical area encompassing mainly desert but also agricultural, rural, and urban communities.

The statistical service life analysis for this account indicates consistent indications with average service lives around the mid–50s for bands with lower censoring and conformance indexes.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

An analysis of the single subpopulation of poles indicates a 53–R1 projection life–curve at 46 percent censoring. This indication is comparable to indications obtained for the full band statistical service life analysis.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Poles	2,191,572,261	89	53-R1	46.0
Non-unitized	271,814,095	11		
Total	2,463,386,356	100	53	

Table 2. Major Structural Components

LIFE ESTIMATION

Based on these indications of a slightly longer projection life than currently approved, a 55–R1 projection life–curve is recommended for this account.

NET SALVAGE

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –505.0 percent, realized from $144.7M of retirement activity constituting 5.5 percent of derived addition over the period 2002–2015. More recent 5–year rolling bands ending in 2013, 2014,and 2015 exhibit negative net salvage rates exceeding –600 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –180 and –488 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and three percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −488 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

Distribution Plant
Account: 365.00 – Overhead Conductors and Devices

Description

This account includes the cost installed of overhead conductors and devices used for distribution purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R0.5	55-R0.5
Future NS Rate	-115.0%	-538.0%
Realized NS	-206.4%	
Average Age (yrs.)	16.7	
Derived Additions	$1,571,387,374	
Plant Retirements	$138,400,064	
Percent Retired	9.7%	
Plant Balance	$1,432,987,310	

Table 1. Account Parameters and Statistics

Life Analysis

Rebuild programs and relocation to address changes in capacity and rights of way, deterioration resulting from atmospheric corrosion, fatigue failure due to conductor vibration, storm damage, and splice failure are the major forces of retirement acting upon this plant category. Lightning strikes also nick the conductor, reducing its capacity and eventually causing burndown. Although repair at the damaged point is possible with splicing and reconnecting, it is costly. It is common, therefore, to remove and replace a longer section of the damaged conductor, which is usually the span between supports. Overhead to underground facilities conversion, such as that governed by CPUC Rule 20, continues to be a force of retirement acting upon this account.

The statistical service life analysis for this account is based on moderately censored trials with censoring exceeding 47 percent. A number of first and second–degree polynomials indications derived from graduated hazard rates that are unrealistically declining or zeroed were rejected. Origin–modal dispersions in which chance is a more pervasive force of retirement were also rejected. More consistent indications for bands with lower censoring and conformance indexes indicated average service lives between 36 and 65 years and lower modal dispersions.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below. Equipment classified in the "Other" category includes primarily circuit breakers and fuse holders.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Overhead Conductor	946,696,334	66	70-R0.5	65.3
Switches	347,104,388	24	42-S0	26.7
Non-unitized	52,173,406	4		
Other	87,013,183	6	24-O3	3.8
Total	1,432,987,311	100	60	

Table 2. Major Structural Components

An analysis of the subpopulations indicates service lives between 24 and 70 years with lower modal dispersions and a dollar–weighted average of 60 years. Service–life indications derived from a statistical analysis of the combined subpopulations are considered to be within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, non–homogeneous plant category.

LIFE ESTIMATION

Based on these observations and considerations, a 55–R0.5 projection life–curve is recommended for this account based upon the more consistent indications for bands with lower censoring and conformance indexes in both the full account and subpopulation statistical service−life analysis.

Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category. Although not equivalent to dollar–years of service, SCE engineers estimate the mean time to wear–out of an overhead capacitor bank is about 30 years. Approximately 11,388 capacitor banks were installed in the overhead system at year–end 2015.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –206.4 percent realized from $138,400,064 of retirement activity constituting 8.8 percent of derived addition over the period 2002–2015. More recent 5–year rolling bands ending in 2013, 2014,and 2015 show negative net salvage rates exceeding –300 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –195 and –538 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and three percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −538 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 366.00 – UNDERGROUND CONDUIT

DESCRIPTION

This account includes the installed cost of underground conduit and tunnels used for housing distribution cables or wires. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	59-R3	59-R3
Future NS Rate	-30.0%	-401.0%
Realized NS	-183.1%	
Average Age (yrs.)	14.2	
Derived Additions	$1,848,035,134	
Plant Retirements	$36,174,527	
Percent Retired	2.0%	
Plant Balance	$1,811,860,607	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Conduit failures are generally the result of mechanical damage caused by excavating or drilling crews inadvertently digging into or drilling through the duct. The statistical service life analysis for this account is based on highly censored trials with indicated average service lives exceeding 70 years. Additionally, only minimal retirement activity of $36M from derived additions exceeding $1.8B has been reported. Constituting 2.0 percent of derived additions, this retirement activity is considered insufficient to provide a reliable basis for service life estimation.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Conduit	789,932,796	44	93-S3	93.0
Pull and Slab Boxes	447,741,061	25	50-S2	50.5
Vaults	324,651,530	18	79-S2	80.6
Excavation Trenches	16,836,983	1	184-R4	100.0
Non-unitized	75,629,378	4		
Other	157,068,859	9	49-L1	45.0
Total	1,811,860,607	100	76	

Table 2. Major Structural Components

Equipment classified in the "Other" category includes primarily risers, manholes, and blower assemblies.

As noted with the full account analysis, high censoring of the subpopulations also produces indeterminate service life indications.

LIFE ESTIMATION

With consideration given to the minimal retirement experience in this account and the resulting unreliable service–life indications, Foster Associates deferred to the Company in recommending retention of the currently approved 59–R3 projection service–life parameters.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –183.1 percent. As noted above, however, this history provides minimal retirement activity over the period 2002–2015.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –108 and –401 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions..

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −401 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 367.00 – UNDERGROUND CONDUCTORS AND DEVICES

DESCRIPTION

This account includes the installed cost of underground conductors and devices used for distribution purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R0.5	43-R1.5
Future NS Rate	-60.0%	-261.0%
Realized NS	-155.7%	
Average Age (yrs.)	11.0	
Derived Additions	$5,946,990,287	
Plant Retirements	$398,585,960	
Percent Retired	7.2%	
Plant Balance	$5,548,404,327	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The majority of SCE's underground cable population is XLPE, which generally fails due to breakdown of insulation over time. The statistical service life analysis for this account indicates average service lives in a narrow range between 40.5 and 44.7 years with lower modal dispersions for trials with lower censoring, conformance indexes, and hazard functions not compromised by negative or declining rates.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Cable	4,452,641,073	80	45-R2	18.6
Non-unitized	288,856,647	5		
Other	809,879,908	15	27-L1	18.1
Total	5,551,377,628	100	42	

Table 2. Major Structural Components

Equipment classified in the "Other" category includes primarily circuit breakers and switches.

An analysis of the subpopulations indicates a 27–L1 and a 45–R2 service life curves with lower modal dispersions and a dollar–weighted mean of 42 years. Service–life indications derived from a statistical analysis of the combined subpopulations are considered to be within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, non–homogeneous plant category.

LIFE ESTIMATION

Based on these observations and considerations, a 45–R1.5 projection life–curve is recommended for this account. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

Although not equivalent to dollar–years of service, SCE engineers estimate a mean time to failure (MTTF) of 41 years for cross–linked polyethylene (XLPE) and 46 years for tree retardant cross–linked polyethylene (TR–XLPE) conductor. Company engineers also estimate that the mean time to wear–out of underground mainline and radial oil switches is about 35 years and the mean time to wear–out of an underground capacitor bank is about 30 years and 25 years for automatic reclosers. Approximately 11,549 subsurface oil–filled switches, 2,253 capacitor banks and 47 automatic reclosers were installed in the underground system at year–end 2015.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –155.7 percent realized from $398,585,960 of retirement activity constituting 6.7 percent of derived addition over the period 2002–2015. The most recent four 5–year rolling bands show negative net salvage rates exceeding –150 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –112 and –261 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −261 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 368.00 – LINE TRANSFORMERS

DESCRIPTION

This account includes the investment in overhead and underground distribution line transformers used in transforming electric energy to secondary voltages. Equipment continues to be classified in this account regardless of whether actually in service or held in reserve for future use. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	33-R1	33-S1.5
Future NS Rate	-20.0%	-47.0%
Realized NS	-46.9%	
Average Age (yrs.)	12.5	
Derived Additions	$4,034,390,510	
Plant Retirements	$525,751,213	
Percent Retired	15.0%	
Plant Balance	$3,508,639,297	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Distribution transformers are replaced when they fail in service or when deterioration is observed during inspection or other field work. Deterioration includes leaks, corrosion and damage caused by vehicles or acts of nature. The statistical service life analysis for this account is stable and indicates average service lives in the mid–20s to high–30s and lower modal dispersions for bands with lower censoring and conformance indexes. It should be noted, however, that "cradle–to–grave" accounting is used for line transformers and associated equipment (*e.g.*, capacitors and network protectors). Service lives indicated from a statistical analysis provide estimates of the age at which transformers are permanently retired from service.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	%	Full Band PLife-Curve
Undeground Transformers	1,262,937,734	36	34-S2
Overhead Transformers	1,045,618,106	30	40-S2
Fuseholders	749,306,101	21	38-S3
Non-unitized	57,769,013	2	
Other	393,008,343	11	25-O2
Total	3,508,639,297	100	36

Table 2. Major Structural Components

An analysis of the subpopulations indicates average service lives between 25 and 40 years with lower modal dispersions and a dollar–weighted mean of 36 years. Service–life indications derived from a statistical analysis of the combined subpopulations are considered to be within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

LIFE ESTIMATION

Service–life indications from both the full account and subpopulation polynomial analyses bound the currently approved 33–S1.5 projection life–curve. Adjusting the currently approved parameters would imply a degree of precision beyond that which can be measured or estimated from a statistical life analysis.

Based on these considerations, retention of a 33–S1.5 projection–life is recommended for this account.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –46.9 percent realized from $525.8M of retirement activity constituting 13.0 percent of derived addition over the period 2002–2015. Most recent 5–year rolling bands show negative net salvage rates exceeding –130 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –27 and –47 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −47 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 369.00 – SERVICES

DESCRIPTION

This account includes the installed cost of overhead and underground services used for distribution purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R1.5	45-R1.5
Future NS Rate	-100.0%	-387.0%
Realized NS	-271.0%	
Average Age (yrs.)	17.2	
Derived Additions	$1,347,309,968	
Plant Retirements	$45,902,562	
Percent Retired	3.5%	
Plant Balance	$1,301,407,406	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Overhead (OH) services are typically installed in older urban areas and remote rural areas where it is cost prohibitive to install conductor underground. Services are installed underground (UG) in newer urban areas and in new rural areas under development. Forces of retirement acting upon UG services are comparable to those acting upon UG primary conductors such as operating temperature, insulation type, vintage of cables, installation method, manufacturing quality, corrosive environment and where installed.

The statistical service life analysis for this account is based on highly censored (63-79 percent) samples producing unreliable service–life indications for a majority of trials. The analysis reveals a few inconclusive indications with service lives between the low–40s and mid–60s.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
UG Service Conductor	783,834,596	60	71-S2	85.4
OH Service Conductor	387,892,896	30	52-R1.5	70.6
Risers	63,694,659	5	64-R2	77.8
Non-Unitized	21,112,757	2		
Other	44,872,497	3	79-R2	82.1
Total	1,301,407,406	100	65	

Equipment classified in the "Other" category includes primarily underground conduit.

An analysis of the subpopulations indicates full–band average service lives between 52 and 79 years with lower modal dispersions and a dollar–weighted mean of 65 years. Subpopulation service life indications are similarly based on highly censored trials and the resulting indications are considered less than conclusive.

LIFE ESTIMATION

Neither the full account nor the subpopulation analysis provides sufficient evidence to warrant adjusting the currently approved 45–R1.5 projection life and curve. It was also revealed in conducting the analysis of this account that the pricing and vintaging of retirements may be contributing to the observed high degrees of censoring. Pending further investigation of the ageing of retirements, Foster Associates concurs with SCE that current parameters should be retained for this account.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –271.0 percent realized from $45.4M of retirement activity constituting 3.4 percent of derived addition over the period 2002–2015. The most recent three 5–year rolling bands show negative net salvage rates exceeding –500 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –178 and –387 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions..

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −387 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

Distribution Plant
Account: 370.00 – Meters

Description

This account includes the cost of smart meters, devices and related appurtenances for use in measuring the electricity delivered to its users, whether actually in service or held in reserve. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	20-R3	20-R3
Future NS Rate	-5.0%	0.0%
Realized NS	-2.4%	
Average Age (yrs.)	7.7	
Derived Additions	$896,271,606	
Plant Retirements	$1,349,434	
Percent Retired	0.2%	
Plant Balance	$894,922,172	

Table 1. Account Parameters and Statistics

Life Analysis

SCE has a population of slightly over 5 million installed meters. With the exception of a small number (less than 20 thousand) of electromechanical meters, AMI meters have been deployed systemwide. A large–scale migration to AMI meters began in 2009 following a pilot program in 2007–2008. The relatively recent deployment of AMI meters produces an insufficient sample of retirements to draw inferences from a statistical analysis. Censoring is about 99 percent.

Life Estimation

AMI meters are electronic devices encased in plastic, typically installed in harsh environments, exposed to extreme weather conditions, and targets for vandalism. While the metrology element used in smart meters is generally considered mature and reliable technology, the life–span of the communication element is far from certain. Metering communication technology and protocols overlaid on electronic meters are rapidly evolving and will likely accelerate the rate of smart meter replacements relative to older–style, electromechanical metering equipment.

Lacking life analysis indications, the service life estimation for this account is based on a consideration of design life (20 years) and the opinions of Company engineers and operations personnel familiar with smart meters and ever evolving communications technology. Foster Associates therefore deferred to SCE in recommending retention of the currently approved 20–R3 projection life–curve for this account.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account is based upon a minimal amount of $1.3M retired between 2011 and 2015 from derived additions exceeding $896M. The analysis indicates an overall net salvage rate of –271.0 percent realized from $45.4M of retirement activity constituting 3.4 percent of derived addition over the period 2002–2015. The most recent three 5–year rolling bands indicate negative net salvage rates exceeding –500 percent. The historical net salvage recorded in this account is not considered to be a reasonable predictor of future net salvage for AMI meters.

NET SALVAGE ESTIMATION

Noting that "cradle–to–grave" accounting is used for meters and associated equipment (*e.g.*, current and potential transformers), minimal salvage and cost of disposal are expected for this account. Meter removal and reinstallation costs are charged to expense. Based on these observations and expectations, a zero percent future net salvage rate is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 373.00 – STREET LIGHTING AND SIGNAL SYSTEMS

DESCRIPTION

This account includes the installed cost of equipment used wholly for public overhead street and highway lighting. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	40-L0.5	48-L1
Future NS Rate	-30.0%	-100.0%
Realized NS	-111.3%	
Average Age (yrs.)	15.5	
Derived Additions	$974,350,403	
Plant Retirements	$102,266,782	
Percent Retired	11.7%	
Plant Balance	$872,083,621	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

During the last 15 years, SCE undertook an accelerated steel pole replacement program to address structural integrity deterioration and related public safety concerns. Pole deterioration found during this program was attributable to atmospheric and water corrosion, and pole, nut and anchor bolt rust. The majority of retired poles were replaced with concrete poles.

The Company conducts annual compliance patrolling and visual inspection of systems and facilities to identify safety issues early. The potential service life of concrete poles is enhanced by adding chlorine ion intrusion inhibitors and using high quality attachments with galvanized coatings.

The major forces of retirement for street light poles include car accidents, deterioration, idled facilities, and street upgrades and relocations.

The statistical service life analysis for this account is reasonably stable for trials with lower censoring, conformance indexes, and non–negative fitted hazard functions. Indications from such trials support average service lives between the lower 40s and mid–50s.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

An analysis of the subpopulations indicates full–band average service lives between 27 and 67 years with lower modal dispersions and a dollar–weighted mean of 54 years. Service–life indications derived from a statistical analysis of the

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Poles	388,111,928	46	58-S0.5	48.9
Cable & Conduit	260,964,203	31	67-R2	66.3
Light Fixtures	177,270,403	21	27-S0	2.4
Non-unitized	22,542,405	3		
Other	23,194,681	3	39-O2	38.3
Total	872,083,621	100	54	

Table 2. Major Structural Components

combined subpopulations are considered to be within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

Life Estimation

Based on these considerations and observations, a 48–L1 projection life–curve, derived from the full account broadest placement and observation bands, is considered reasonable and is recommended for this account.

Net Salvage Analysis

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –111.3 percent realized from $102,266,782 of retirement activity constituting 10.5 percent of derived addition over the period 2002–2015. The most recent 5 and 10–year rolling bands indicate net salvage rates exceeding –115 percent.

Net Salvage Estimation

Based on these observations and the historical net salvage analysis, retention of the currently approved –100 percent future net salvage rate is recommended for consideration by SCE. It appears unlikely that lesser amounts of cost of removal will be realized in the future.

GENERAL PLANT DEPRECIABLE
ACCOUNT: 390.00 – STRUCTURES AND IMPROVEMENTS

DESCRIPTION

This account includes the cost in place of structures and improvements used for Company purposes, the cost of which is not properly includible in other structures and improvements accounts. Account statistics and current and proposed parameters are shown in Table 1 and the composition of major structural components classified in this account at December 31, 2015 is shown in Table 2.

	Current	Proposed
Plife-Curve	38-R3	45-R0.5
Future NS Rate	-5.0%	-10.0%
Realized NS	-24.5%	
Average Age (yrs.)	12.7	
Derived Additions	$1,035,908,700	
Plant Retirements	$88,821,443	
Percent Retired	9.4%	
Plant Balance	$947,087,257	

Table 1. Account Parameters and Statistics

	Investment	
Category	Amount ($)	%
Common	229,531,472	24
Buildings	220,785,582	23
Power & Lighting Systems	170,306,642	18
HVAC	100,134,622	11
Alarms and Monitoring Systems	65,852,228	7
Foundations & Related Structures	57,908,077	6
Water Supply Systems	33,133,484	3
Non-unitized	27,376,214	3
Miscellaneous	42,058,937	4
	947,087,257	100

Table 2. Structural Components Distribution

LIFE ANALYSIS

The statistical service life analysis for this account indicates average service lives between 40 and 60 years for trials with lower censoring and conformance indexes. A number of trials are considered less reliable if hazard rates are unrealistically declining or zeroed to avoid the suggestion of negative hazard rates. No attempt was made to analyze equipment classified in the subpopulations for this plant category.

LIFE ESTIMATION

Based on the indications obtained from the broader bands of the statistical life analysis, a 45–R0.5 projection life–curve is recommended for this account. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

NET SALVAGE ANALYSIS

The historical net salvage analysis for this account indicates an overall adjusted net salvage rate of –24.1 percent realized from $88.8M of retirement activity constituting 8.6 percent of derived addition over the 2002–2015 study period.

NET SALVAGE ESTIMATION

Based on these observations and the expectation of continuing negative net salvage, a –10 percent future net salvage rate is recommended for consideration by SCE. This recommendation adjusts the future net salvage parameter from a –5 percent in the direction of the historical net salvage observations.

Appendix B

Formulation of Per Unit Net Salvage Rates

FORMULATION OF PER-UNIT NET SALVAGE RATES

Average realized net salvage per unit retired for the kth subpopulation of a plant account is given by

$$\overline{NSR_k} = \frac{\sum_{2009}^{2015} NSR_{jk}}{\sum_{2009}^{2015} NUR_{jk}}$$

where

NSR_j = net salvage realized in the j^{th} activity year; and
NUR_j = number of units retired in the j^{th} activity year.

The installed cost per unit of plant remaining in service at December 31, 2015 from the i^{th} vintage of the kth subpopulation of a plant account is given by

$$ICU_{ik} = \frac{PIS_{ik}}{NUS_{ik}}$$

where

PIS_{ik} = plant in service from the i^{th} vintage of the k^{th} subpopulation; and
NUS_{ik} = number of units in service from the i^{th} vintage of the k^{th} subpopulation.

The ratio of the net salvage per unit retired to the installed cost of the i^{th} vintage of the kth subpopulation of a plant account becomes

$$PUR_{ik} = \frac{\overline{NSR_k}}{ICU_{ik}}.$$

The plant–weighted average of vintage subpopulation ratios used to estimate the future net salvage of vintages at the account level (*i.e.*, the sum of subpopulation vintages) is given by

$$\overline{PUR_i} = \frac{\sum_{k=1}^{n} (PIS_{ik})(PUR_{ik})}{\sum_{k=1}^{n} PIS_{ik}}$$

where

n = number of subpopulations within a plant account.

Forecasted retirements from the i^{th} vintage in the jth activity year are the product of plant in service at December 31, 2015 and the probability of retirement in activity years beyond 2015 obtained from an Iowa–type probability density function. Retirements from the i^{th} vintage in the j^{th} activity year are given by

$$RET_{ij} = \left(PIS_i\right)\left(p_{ij}\right)$$

where

p_{ij} = probability of retirement during age interval $j–i–0.5$ and $j–i+0.5$.

Estimated future net salvage for retirements from the i^{th} vintage in the j^{th} activity year is given by

$$FNS_{ij} = RET_{ij}\left(\overline{PUR_i}\right)\left(1+r\right)^{j-2015}$$

r = estimated rate of inflation.

where

The estimated future net salvage rate for a plant account is the ratio of the sum of future net salvage to the sum of vintaged plant in service given by

$$FNS = \frac{\sum_i \sum_j FNS_{ij}}{\sum_i \sum_k PIS_{ik}},.$$

QUESTION:
Please file with the PSC any documents the Company may have in support of its response to Data Request No. 12.

RESPONSE:
Please refer to FPL's response to Staff's First Request for Production of Documents No. 1.