X. APPENDIX AND SCHEDULES

Appendix

Appendix REN-1	Ron Nelson Resume Summary

Schedules

Schedule REN-1	OCA 2-060
Schedule REN-2	OCA TS 3-007
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Schedule REN-4	OCA 7-001A - Attachment
Schedule REN-5	OCA 7-002E, tab "Att. OCA 7-002E, Pg. 680" in Attachment
Schedule REN-6	OCA 7-004
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Schedule REN-13	Docket No. DE 19-064, Request No. Staff 9-17.
Schedule REN-14	OCA 2-054

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PROFESSIONAL BACKGROUND AND EDUCATION

EDUCATION

M.S. **Agricultural and Resource Economics**
Colorado State University, Fort Collins, CO, 2013

Minor **Mathematics**
Western Washington University, Bellingham, WA, 2011

B.A. **Environmental Economics**
Western Washington University, Bellingham, WA, 2006

EMPLOYMENT

2018 - Present	Senior Manager, Strategen Consulting
2013 – 2017	Utilities Economist, Antitrust and Utilities Division, Office of the Minnesota Attorney General
2012 – 2013	Consulting Economist, United States Geological Survey
2011 – 2013	Economic Research Assistant, Colorado State University

PREVIOUS TESTIMONY

Company	**Docket No.**	**Subject**
Oklahoma Gas and Electric	201800140	CCOSS and Rate Design
Public Service Company of Oklahoma	201800096	Rate Design and Performance-Based Regulation
Vectren Energy Delivery of Ohio	18-0298-GA-AIR	CCOSS and Rate Design
Commonwealth Edison	18-0753	Distributed Generation Rebates
Ameren Illinois Company	18-0537	Distributed Generation Rebates
Oklahoma Gas and Electric	201700496	CCOSS and Revenue Apportionment
Minnesota Power	E-002/GR-16-664	CCOSS, Rate Design, and the Utility Business Model
Otter Tail Power	E-002/GR-15-1033	Marginal and Embedded CCOSS and Rate Design
Xcel Energy	E-002/GR-15-826	CCOSS, Rate Design, and Performance-Based Regulation
Minnesota Energy Resources Corp.	G-011/GR-15-736	CCOSS and Rate Design
CenterPoint Energy	E-002/GR-15-424	CCOSS and Rate Design
Dakota Energy Association	E-002/GR-14-482	CCOSS and Rate Design
Xcel Energy	E-002/GR-13-868	CCOSS and Rate Design
Minnesota Energy Resources Corp.	G-011/GR-13-617	CCOSS
CenterPoint Energy	G-008/GR-13-316	CCOSS

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 06/24/2019 | **Date of Response: 07/09/2019**
Request No. OCA 2-060 | **Page 1 of 2**
Request from: Office of Consumer Advocate

Witness: Eric H. Chung, Troy Dixon

Request:
Please provide a list of benefits that will accrue to ratepayers, if Eversource's step increases are approved. Quantify the benefits where practical.

Response:
Without a mechanism akin to step increases in rates, a utility faces "attrition" following a rate case where the utility makes expenditures after a test year for capital projects that are placed in service for the provision of safe and adequate service to customers. The N.H. Supreme Court described the concept of "attrition" in New England Tel. & Tel. Co. v. State, 113 N.H. 92, 97 (1973) as an:

> [E]rosion in earning power of a revenue-producing investment. This erosion is a complex phenomenon, the result of operating expenses or plant investment, or both, increasing more rapidly than revenues. If attrition occurs, the result would be that the rate of return realized in the future would be below that which rates were designed to produce. This effect is apt to occur in a period of comparatively high construction costs when new plant is being added …. As the high cost plant comes into service, it tends to increase the applicable rate base at a more rapid pace than the resultant earnings, and the rate of return decreases accordingly.

In that case, the Supreme Court noted that, under New Hampshire law, "[i]f the existence of attrition can be established by the company the commission should evaluate the impact of this factor on the earnings of the utility and make an appropriate allowance for it."

In PSNH's last rate case the Commission appropriately relied on this requirement that it "make an appropriate allowance" to deal with attrition when it approved step adjustments in that case. *See* PSNH, Docket No. DE 09-035, Order No. 25,123 (June 29, 2010 at page 30).

The Commission has authorized step increases in rates to allow recovery of expenditures made after a test year for capital projects that are subsequently placed in service and are necessary for the provision of safe and adequate service. Pennichuck Water Works, Inc., Order No. 23,923, 87 NHPUC 97, 102 (2002); Eastman Sewer Co., Inc., Order No. 25,271, 96 NHPUC 437 (Aug. 4, 2011).

The Commission has also held, "Step adjustments to rates are employed as a means of ensuring that a regulated utility retains its ability to earn a reasonable rate of return after implementing large capital projects, and to avoid placing a utility in an earnings deficiency immediately after a rate case in which a revenue requirement was based on a historical test year." Lakeland Mgmt. Co., Inc., Order No. 25,357, (May 1, 2012) at 13.

As the proposed step adjustments meet a requirement contained in prevailing New Hampshire law as espoused by the Supreme Court, and are consistent with Commission precedent, there is an innate benefit to customers from this ratemaking mechanism.

Consistent with established Commission precedent, the step adjustment approach represents a reasonable method of balancing the Company’s need to maintain a level of financial integrity to support continued investment between rate cases to safely and reliably serve its customers. The step adjustment process allows for more timely recovery of a portion of assets placed in service, positioning the Company to defer or prolong the need for another rate case soon after completing one. Using the Company's 2009 rate case (DE 09-035), the most recent electric rate case for Unitil (DE 16-384) and the most recent electric rate case for Liberty (DE 16-383) as examples, step adjustments after permanent rates were established were a major factor that contributed to another rate case not needing to be filed shortly afterwards.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 11/06/2019 **Date of Response: 11/22/2019**
Request No. OCA TS 3-007 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Joseph A. Purington, Lee G. Lajoie

Request:
Reference OCA 8-050 and 7-021. When asked "What characteristics of DERs is the Company explicitly planning for? Increased hosting capacity? Proactively addressing voltage issues?" The Company responded during the technical conference with an affirmative and stated, "All those things and many more." Provide evidence that supports the Company's claim. Include in your response, how the Company's base capital plan and GTEP proposal explicitly integrate these concepts.

Response:
The Company is actively planning for increased penetration of inverter based systems and actively maintaining its distribution system to increase resiliency. Inverter based systems pose a unique challenge in that these systems require the utility distribution system to set and maintain frequency and voltage. In the future, without a resilient distribution system as a foundation, isolation of customer load and generation can have a much larger effect on the overall security of the system. To this end of creating a more resilient system the company is constructing lines with larger conductors, constructing circuit ties, replacing electromechanical relays with microprocessor based relays, replacing older mechanical load tap changer controls on substation transformers with micro-processor based controls, expanding SCADA control of distribution capacitor banks, and evaluating new technologies such as DVAR STATCOM units to be installed instead of large station capacitor banks, The Company's base capital plan includes projects to replace small conductors with larger, construct circuit ties, replace electromechanical relays with microprocessor based relays, and replace older mechanical load tap changer controls on substation transformers with micro-processor based controls, Replacing small conductors with larger and replacing electromechanical relays with microprocessor based relays would also be part of GTEP, which is intended to speed up the process by accelerating the replacement of these aged assets.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 09/11/2019 **Date of Response: 09/25/2019**
Request No. OCA 7-003 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Edward A. Davis, Amparo Nieto

Request:
Reference Nieto Direct at 6, lines 3-4 stating, "[t]he MS study involves the following steps (also described on pages 90-92 of the NARUC manual)." Please provide the steps from pages 90-92 of the NARUC Electric Manual that the Company did not follow. Include in your answer, but do not limit it to, responses to the following questions:

a. Did the Company utilize the minimum size method for FERC 369?
b. Did the Company utilize the minimum size method for FERC 364?
c. For each FERC account that the minimum size method was used:
 i. Did the Company use the minimum size equipment "currently being installed" on the distribution system?
 ii. Did the Company use "average book cost?" If not, provide a detailed explanation of the approach used by the Company.

Response:
a. The Company's ACOSS follows the widespread industry practice of not applying a minimum system approach to FERC Account 369 - Services. Instead the entire account is classified as customer-related. Ms. Nieto´s Direct statement at 6, lines 3-4 alludes to the general method identified in the NARUC manual in pages 90-92, which was followed when the Company conducted the Minimum System (MS) study. The fact that the Company's MS study only applied to the assets in FERC Accounts 364-368 and not those in Account 369 does not mean that the Company's approach was misaligned with NARUC manual's recommended approach. While the NARUC manual indicates that the MS approach can be applied to FERC account 369, NARUC does not endorse this approach for that asset type. This can be concluded from reading other sections of the NARUC manual (see for example Table 6-1 "Classification of Distribution Plant" in page 87, where NARUC sees FERC account 369 as a customer-related cost). Another important consideration is that application of a minimum system approach is not generally feasible for services. Many utilities, including the Company, do not have detailed property records or total number of feet of service drops. Thus, they lack the necessary detail in the inventory data to apply the MS steps to services with sufficient accuracy.

The treatment of Account 369 in the Company's ACOSS follows NARUC´s characterization of the nature of service drops in the Cost allocation Manual. On page 96, in reference to Account 369, the NARUC manual states the following: "This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops". Ms Nieto developed cost allocators for Account 369 in the ACOSS that did take into account the size of the customer load, by virtue of considering whether the customer class used primarily single-phase service vs. three-phase service or a mix of both.

b. Yes. The worksheet for Account 364 was inadvertently omitted from the Company's response. Please see Attachment OCA-7 002E in the Company's response to Q-OCA 7-002 for the minimum system study for Account 364.

c.

i. Yes. The specific types of conductor, pole or transformer that the Company's MS Study used to set the minimum equipment cost for the respective accounts correspond to the smallest size asset that the Company may currently install to provide service (i.e., the assets considered are not technologically obsolete).

ii. The Company MS study uses an interpretation of the average installed book cost which takes into account original installed cost (or gross book value of all assets in the account, before depreciation) restated in 2018 dollars using Handy-Whitman. The study differentiates plant by primary or secondary voltage, phase of service, and/or by underground or overhead, whenever this level of detail was available in the property records. Using this approach allows for a comparison of total plant cost by FERC account with the typical installed cost of the minimum sized equipment (the smallest asset the Company currently uses to provide service or connect a customer to the grid) in each account. Identifying the minimum asset cost involved consulting with the Company's engineering group. This process creates a minimum size cost that is current and not distorted by vintage of installation. The percentage of customer-related costs in each FERC account calculated by the MS study is the result of dividing the current total installed costs of the minimum sized asset (typical minimum size cost times total feet or units in the account), by the total Handy-Whitman adjusted (i.e., "Current") cost of plant booked in the account. The respective weights to calculate the weighted average are feet of conductor or number of units by type compared to total feet or total number units in the inventory for each account, all stated in 2018 dollars.

Account 364 - Primary (Fully Owned) Minimum Size Cost

Pole - 45 Foot Class 2 (Fully Owned)

Labor Hours		
WORK TASKS	2.48	
SETUP/SPAN	0	
TRAVEL....	0	
TOTAL.....	2.48	
Labor Cost		
$/hour	$47.52	
	$117.85	
Labor Loaders		
Nonprod	33.2%	$39.07
Labor	14.9%	$23.32
Direct Eng	12.8%	$23.00
Total		$85.39
Total Labor		$203.24
Equipment Hours	1.24	
Equipment Rate	$33.27	
Equipment Cost		$41.25
Material Cost		$566.86
Material Loader	13.75%	$77.94
Material Total		$644.80
Loaders		
Eng & Sup	41.5000%	$84.35
Small Tool	2.3333%	$4.74
AS&E	0.7917%	$7.04
Total		$96.13
Total Cost		$985.43

Account 364 - Primary (Jointly Owned) Minimum Size Cost

Pole - 45 Foot Class 2 (Jointly Owned)

Labor Hours		
WORK TASKS	2.48	
SETUP/SPAN	0	
TRAVEL....	0	
TOTAL.....	2.48	
Labor Cost		
$/hour	$47.52	
	$117.85	
Labor Loaders		
Nonprod	33.2%	$39.07
Labor	14.9%	$23.32
Direct Eng	12.8%	$23.00
Total		$85.39
Total Labor		$203.24
Equipment Hours	1.24	
Equipment Rate	$33.27	
Equipment Cost		$41.25
Material Cost		$283.43
Material Loader	13.75%	$38.97
Material Total		$322.40
Loaders		
Eng & Sup	41.5000%	$84.35
Small Tool	2.3333%	$4.74
AS&E	0.7917%	$4.49
Total		$93.58
Total Cost		$660.48

Account 364 - Secondary (Fully Owned) Minimum Size Cost

Pole - 35 Foot Class 4 (Fully Owned)

Labor Hours		
WORK TASKS	1.6855	
SETUP/SPAN	0	
TRAVEL....	0	
TOTAL.....	1.6855	
Labor Cost		
$/hour	$47.52	
	$80.09	
Labor Loaders		
Nonprod	33.2%	$26.56
Labor	14.9%	$15.85
Direct Eng	12.8%	$15.63
Total		$58.04
Total Labor		$138.13
Equipment Hours	0.84	
Equipment Rate	$33.27	
Equipment Cost		$28.04
Material Cost		$372.86
Material Loader	13.75%	$51.27
Material Total		$424.13
Loaders		
Eng & Sup	41.5000%	$57.33
Small Tool	2.3333%	$3.22
AS&E	0.7917%	$4.67
Total		$65.22
Total Cost		$655.52

Account 364 - Secondary (Jointly Owned) Minimum Size Cost

Pole - 35 Foot Class 4 (Jointly Owned)

Labor Hours		
WORK TASKS	1.6855	
SETUP/SPAN	0	
TRAVEL....	0	
TOTAL.....	1.6855	
Labor Cost		
$/hour	$47.52	
	$80.09	
Labor Loaders		
Nonprod	33.2%	$26.56
Labor	14.9%	$15.85
Direct Eng	12.8%	$15.63
Total		$58.04
Total Labor		$138.13
Equipment Hours	0.84	
Equipment Rate	$33.27	
Equipment Cost		$28.04
Material Cost		$186.43
Material Loader	13.75%	$25.63
Material Total		$212.06
Loaders		
Eng & Sup	41.5000%	$57.33
Small Tool	2.3333%	$3.22
AS&E	0.7917%	$2.99
Total		$63.54
Total Cost		$441.78

Schedule REN-5

Primary / Scondary		
Feet	Pri	Sec
10	0%	100%
15	0%	100%
18	0%	100%
20	0%	100%
25	4%	96%
30	18%	82%
35	78%	22%
40	94%	6%
45	96%	4%
50	97%	3%
55	96%	4%
60	95%	5%
65	94%	6%
70	94%	6%
75	90%	10%
80	100%	0%
85	100%	0%
90	100%	0%
95	100%	0%
100	100%	0%
115	100%	0%
135	100%	0%
<= 35FT	55%	45%
> 35FT	95%	5%
51FT - 55FT	96%	4%
53FT - 55FT	96%	4%
56FT - 60FT	95%	5%
61FT - 65FT	94%	6%
66FT - 70FT	94%	6%

Count of Heights by Pri / Sec			
Pole Height	Pri	Sec	Total
25	858	18,326	19,184
30	9,754	43,111	52,865
35	99,469	28,105	127,574
40	147,881	8,856	156,737
45	35,233	1,599	36,832
50	5,748	208	5,956
55	1,592	59	1,651
60	684	36	720
65	320	22	342
70	130	9	139
75	82	9	91
80	29	0	29
85	13	0	13
Grand Total	301,794	100,339	402,133

Weighted Avgs.			
	110,081	89,542	199,623
<= 35FT	55%	45%	100%
	191,713	10,797	202,510
> 35FT	95%	5%	100%

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 09/11/2019 | **Date of Response: 09/26/2019**
Request No. OCA 7-004 | **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Edward A. Davis, Amparo Nieto

Request:
For the minimum system study, please provide the average installed book cost of every size of distribution equipment for FERC accounts 364-369. Where applicable, provide your response in a live Excel spreadsheet with all links and formula intact.

Response:
The Company has calculated the historic average book cost of every size of distribution equipment for FERC Accounts 364, 365, 367 & 368. Please see Attachments OCA 7-004A through D for the requested information, provided as Excel spreadsheets with links and formula intact.

Consistent with the NARUC cost allocation manual, the Company focuses on minimum sized assets currently installed on our system, as provided in the response to Q OCA-001 for the size and cost of the minimum size assets the Company currently installs for these accounts.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 10/11/2019 **Date of Response: 10/25/2019**
Request No. OCA 8-053 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Amparo Nieto, Edward A. Davis

Request:
What percentage of Eversource's circuits are winter peaking? Please provide a narrative description of load and customer types that are leading the circuits to be winter peaking.

Response:
Planning studies are conducted, almost exclusively, based on summer peaks due to the lower equipment ratings during the heat of summer. Previous year's studies have shown that only the areas in Northern NH tend to be winter peaking, with exception of three circuits in the southern part of the state that serve ski areas. Those three circuits' winter peaks are only marginally higher than the summer peaks. Eversource has no reason to believe that any circuits beyond those identified (Northern plus three in the south) are winter peaking. Considering that, the percentage of Eversource circuits that are winter peaking is approximately 10.5% (37 out of 354).

While it is clear that ski areas (snow making and chair lifts) are a significant contributor to the circuit peak, as is electric heat combined with a lack of summer air conditioning, no specific investigation has been conducted to determine the description of load and customer types.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 11/06/2019 **Date of Response: 11/21/2019**
Request No. OCA TS 3-002 **Page 1 of 3**
Request from: Office of Consumer Advocate

Witness: Edward A. Davis, Amparo Nieto

Request:
Provide a list of all the changes made in the Company's MCOS from the time it was filed in the NEM proceeding until its rate case filing.

Response:
The 2019 marginal cost of distribution service study ("MCOSS") incorporated updates to the MCOSS filed in July 2018. The main changes were to the bulk and non-bulk capital budget. The following are a list of these changes as well as other updates.

1. The five year planning period used in the MCOSS was modified to include years 2020 through 2024 as opposed to years 2019-2023.

2. All bulk station peak load projections were updated by the Company and the 2019 MCOSS used the updated projections for years 2020 through 2024.

3. The 2019 MCOSS relied on the updated 2019 Capital plan. This plan includes capacity related bulk and non-bulk station projects during years 2020 - 2024. A review of the Company's updated capital plan revealed a number of changes, such as station projects that had been delayed by a year, or additional station investments. The 2019 MCOSS reflects these changes and excluded projects expected to be in service by 2019. The basis for the station marginal cost calculation and the projects used can be found in tabs W2 and W3 in the 2019 MCOSS, and in tabs W18A and W18B in the 2018 MCOSS.

4. In addition to updating the station projects as per the updated Capital Plan of the Company, the 2019 MCOSS further refines the analysis by excluding certain projects considered by the Company to be driven by a need to modernize the station or improve its condition upon further review. In particular, the station budget item identified as "Anticipated Transformer Replacement" in the prior capital plan was excluded from the 2019 MCOSS. The Company expect the investments in this category, totaling $44m over the 2021-2023 time frame to address asset condition projects. As both the Company and Ms. Nieto have explained in prior responses to the OCA, these investments were not easily classifiable since the dollar amounts were not tied to any specific locations. Instead, it was a provision of funds in the plan to be used for emerging investment needs. The 2018 MCOSS assumed that this budgeted category of investments would involve N-1 capacity replacements since Ms. Nieto had observed a number of bulk stations exceeding the 75 percent design demand threshold over the study period. At the time of updating the MCOSS in 2019 the Company clarified that it will not address all the identified N-1 violations allowing each

bulk station to meet the 75% design criteria by 2024. As a result, it was determined that the investments under the line item mentioned above would include asset condition projects. We note that the 2019 MCOSS marginal substation cost calculation captures the N-0 or N-1 projects that the Company plans to undertake only within the upcoming five year time frame.

5. As a result of the various updates and correction mentioned in bullets #1 and #2 above, the MCOSS calculated a lower share of the system peak served in capacity expansion areas (from about 33.5 percent down to 20 percent), yielding a lower five year system-wide average bulk station marginal cost.

6. The 2019 MCOSS revised the peak load threshold that would trigger replacement of a non-bulk station transformer for a larger one. The Company clarified that in the case of non-bulk stations, the prevailing practice over the foreseeable future is to continue using the transformer's Long Term Emergency ("LTE") rating to determine when expansion of a non-bulk station is required. The July 2018 study used normal nameplate rating to identify when the station was due for expansion. Using LTE ratings, along with the updated loads for year 2018 resulted in fewer non-bulk stations requiring an upgrade, and as a result, the share of peak load in capacity expansion substations during the five year period declined from 23.5% to 5.51%. The lower percentage yields a lower system-wide marginal non-bulk cost as compared to the 2018 MCOSS.

7. The non-bulk substation marginal cost calculation in the 2019 MCOSS also reflects the updated five year capital plan. When reviewing the needed investments, the Company considered lower cost measures to solve constraints at these substations identified as having a capacity constraint. These measures do not involve a transformer replacement. Ms. Nieto learned upon discussions with the Company planners that for the identified constraints, switching load off to a nearby non-bulk substation would take place to prevent the station from exceeding its LTE rating. Ms. Nieto confirmed that this practice is considered prudent under the Company's current reliability standards.

8. The 2019 MCOSS updated the peak/off-peak periods, as a more reasonable alternative to the peak period in the current time of day rates based on the probability of substation peak, updated to include actual year 2018 hourly station loads. This update resulted in more of the annual probability of peak falling in hour 11 am as compared to the July MCOSS, as well as a lower probability of the annual peak falling between 7 and 8 PM.

9. FERC Form 1 expense data for year 2018 regarding distribution Operation & Maintenance ("O&M") expenses were incorporated in the study.

10. Year 2018 number of customers and meters were incorporated into the study.

11. The split of distribution line O&M expense between primary and secondary voltage was revised slightly based on updated disaggregated information on circuit miles. The percent of line O&M expense allocated to local distribution lines (as opposed to lines at 34.5 kVA and above) was revised from 71.31% down to 68.97%.

12. The share of the Company load served from a distribution non-bulk substation was revised from 16.67 percent (based on the 2023 peak load projection) to 17.46 percent (based on 2024 peak load projection).

13. Class weighting factors for customer accounts expenses and customer service and informational expenses were updated to be consistent with the Company's class weighting factors prepared for the Allocated Cost of Service Study.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 11/06/2019 **Date of Response: 11/21/2019**
Request No. OCA TS 3-003 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Edward A. Davis, Amparo Nieto

Request:
Provide the dollar amount that was reclassified from capacity to asset condition related between the NEM and rate case MCOS versions. Additionally, confirm that the impact of this change is a lower estimated marginal volumetric rate.

Response:
The 2019 MCOS study included a revision to the distribution substation projects considered for the calculation of marginal capacity-related station cost. This revision reflected updates to the capital projects provided by the Company, excluding projects already completed in 2019 and adding dollars of station capacity-related investment planned for year 2024, as well as a revision to exclude dollars of investment under the category "Anticipated Station Replacement". This category did not include formalized, identified needs and upon further internal discussion about the most likely nature of the potential projects it was determined that they will primarily be asset condition-related and therefore the associated investments had not been correctly classified in the prior study. The total bulk station investment used in the 2018 MCOS study for the period 2019 – 2023 was $61.9 million. As a result of the updates discussed, the total amount used in the 2019 MCOS study for the period 2020 – 2024 was $27.5 million. The net difference was $34.4 million.

The impact from the correction to dollar of investments associated with capacity expansion reasons on the marginal substation cost was a 46 percent reduction (from $341.1/kW to $182.5/kW) before the annualization step and before calculating the system-wide average cost. An additional adjustment was made to recognize the small share of the Company's service territory loads that will be affected by the planned capacity-related bulk station investments. To calculate the system-wide average investment in bulk stations, the 2018 MCOS study used 33.5% as a weighting factor while the 2019 MCOS study used a revised share of 20.3% (i.e., assumed that 20.3% of the total peak distribution load would be in areas expanding for capacity reasons) consistent with the updates in locations of the planned investments. The revised system-wide marginal bulk station investment was $36.3/kW, down from $112.5/kW, representing a 68 % reduction. This result is more robust as it is consistent with the current state of the Company's distribution system, which has sufficient substation capacity to accommodate projected loads in the majority of its distribution substation areas. The impact of this correction is a lower marginal cost stated on a per-kWh basis or on a demand basis, both measured at the time of the distribution system peak.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 09/11/2019 **Date of Response: 09/25/2019**
Request No. OCA 7-012 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Amparo Nieto

Request:
Reference the response to OCA 2-051A, tab “Cust Ser & Info W21.” If the Company is including any energy efficiency administration costs in FERC 908, please explain why the Company believes these costs should be appropriately recovered through the customer charge.

Response:
The Marginal Cost of Service Study (“MCOSS”) that was filed in May 2019 included some expenses associated with energy efficiency (”EE”) programs that are booked as part of FERC Account 908 - Customer Assistance Expenses. Regardless of potential benefits that energy efficiency may bring to the distribution system (i.e.., by lowering peak loading at constrained substations), Ms. Nieto has updated the MCOSS to exclude all EE program expenses upon confirming that these expenses are recovered entirely outside of the Company´s distribution rates. The updated MCOSS is being filed as Attachment OCA 2-051A (Revised). The updated MCOSS results continue to support the direction of changes by rate component proposed by the Company in the permanent rate case filing. Additionally, the revision does not impact the customer class revenue targets because these were determined based on the ACOSS results.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 09/11/2019 **Date of Response: 09/25/2019**
Request No. OCA 7-010 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Amparo Nieto

Request:
Reference the response to OCA 2-053, stating: “The local maximum demand represents the cost driver for investment in primary tap lines, secondary transformers and secondary lines and is referred to in the MCOSS as the ‘design demand’”. Provide industry and/or academic literature that supports Witness Nieto’s definition of “design demand.”

Response:
Ms. Nieto has used this term when testifying in prior rate cases in Minnesota, New York, and Nevada. In addition, Ms. Nieto discussed “design demand” in an Electricity Journal article published in April 2016. “Optimizing Prices for Small-Scale Distributed Generation Resources: A Review of Principles and Design Elements”. The term “design demand” is not commonly used in academic or industry publications, however; some energy rate design and cost of service experts use the term "connected load", or monthly subscription KW charges, in the context of discussing the appropriate rate components to recover the customer connection costs, which are distinct from recovery through metered demand or energy usage.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 09/11/2019 **Date of Response: 09/25/2019**
Request No. OCA 7-009 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Amparo Nieto

Request:
Reference Nieto Testimony at 16, lines 14-17, stating, "[t]he design demand that the Company considers when installing a transformer and local lines is the maximum load that the customers connected to those facilities are expected to impose on the local distribution system." Please provide all Company documents (internal, filed with the Commission, or otherwise) that explicitly define, reference, or discuss criteria related "design demand."

Response:
Ms. Nieto had conversations early on with the Company to explain her proposed approach to estimate the marginal costs of distribution service. In a MCOSS, the company´s design process is key as it determines the appropriate measure of marginal costs. Ms. Nieto proposed the term "customer design demand" to refer to the estimate of the customer's demand that the Company uses at the time of installation of facilities required for customer connection to the main primary grid, which may involve a secondary line transformer plus local primary lines or secondary conductors.

The term "design demand" concept is not included in the Company´s manuals per se, however, the feedback that Ms. Nieto received from the Company confirmed that the design demand concept is consistent with the Company´s planning practices for local facilities. The Distribution planners´ design standards make implicit or explicit assumptions on the maximum load of the connected customers over the long term, because it **is** more cost-effective and minimizes the need to frequently increase the size of the transformer or conductor as the customer increases load. Thus, the design demand is generally not expected to change over time and it differentiates from the Company´s year to year monitoring of actual peak loads or the near-term load forecasting that is more commonly used at distribution substations or at primary feeders. For residential customers the Company uses transformers of standardized sizes, but the choice of the standard size is again intended to be sufficient to meet the expected long-term maximum load of the customer(s) that will be served from those facilities. For new large customers in rates GV and LG the expected maximum customer load generally dictates the size of the transformer. These customers are responsible for their transformation and they either rent or install their own transformer.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 19-064
Distribution Service Rate Case

Staff Data Requests - Set 9

Date Request Received: 9/26/19	Date of Response: 10/10/19
Request No. Staff 9-17	Respondent: Melissa F. Bartos

REQUEST:

Reference Bartos Testimony. Please provide Liberty's expected increase in primary distribution plant additions over the next 2 to 5 years. Please identify the amount of the primary distribution plant additions that are due to increases in peak demand. For anticipated investments related to increases in peak demand, please provide the total cost, nameplate capacity increase, and anticipated increase in system capacity as evaluated under standard planning conditions.

RESPONSE:

Table 1 on the following pages contains Company information regarding plant additions over the next five years.

Table 1

Project Name 2020 - 2024 Total Cost	Increase in Nameplate Capacity (Increase in System Capacity)	Description of Primary Plant Additions	Description of Secondary Plant Additions	Description of Transformer Plant Additions
Golden Rock Project $5,800,000	55 MVA (79 MVA non firm)	Add one new 55 MVA 115/13 kV transformer and three distribution feeder positions at the Golden Rock substation. One power transformer and two distribution feeders are added in 2019 and one distribution feeder will be added in 2020.The 2020 feeder installation will require approximately 700ft of 3-1000 kCMIL Cu cables and 2.75 miles of 477 spacer cable. Approximately 55 poles will be replaced as part of this new feeder install.	It is not anticipated that the Golden Rock will add considerable secondary plant. It is assumed that the existing secondary wires will be transferred.	Approximately 24 transformers will be replaced along the 2.75 mile reconductoring project.
Rockingham Project $20,100,000	110 MVA nameplate from transformer (92 MVA firm)	Add two new 55 MVA 115/13 kV transformers and six distribution feeder positions in a metalclad switchgear configuration. Approximately 2 miles of 3-1000 kCMIL Cu cables and 2 miles of 477 spacer cable will be added as part of this project.	It is not anticipated that the Rockingham project will add considerable secondary plant. It is assumed that the existing secondary wires will be transferred.	The number of distribution transformers that will be replaced as part of this project has not been determined.
Slayton Hill 39L4 Project $740,000	Not Applicable (One distribution feeder will add approximately 12MVA of capacity.)	The new Slayton Hill 39L4 feeder position will be installed at the Slayton Hill substation to provide load relief to the West Lebanon area from a new customer expansion. Approximately 850 feet of 3-1000 kCMIL Cu cables and one load break will be installed as part of this project.	This project will not add considerable secondary plant.	There will be no distribution transformers replaced as part of this project.

Project Name 2020 - 2024 Total Cost	Increase in Nameplate Capacity (Increase in System Capacity)	Description of Primary Plant Additions	Description of Secondary Plant Additions	Description of Transformer Plant Additions
Mt Support 16L7 Project $740,000	Not Applicable (One distribution feeder will add approximately 12MVA of capacity.)	The new Mt Support 16L7 feeder position will be installed at the Mt Support substation to provide load relief to the North Lebanon area from a new customer expansion .Approximately 900 feet of 3-1000 kCMIL Cu cables will be installed as part of this project.	This project will not add considerable secondary plant.	There will be no distribution transformers replaced as part of this project.
Distribution Transformer Upgrades $375,000	Average increase in nameplate capacity is 25kVA. Assuming 50 replacements / year for the next five years gives 6.25 MVA of increased nameplate capacity. (Not Applicable)	This program aims to reduce excess loading conditions on distribution transformers over a 15 year period. Based on a 15 year program, 50 installations need to be replaced annually. This project will not add considerable distribution plant.	This project will reconfigure existing secondary to balance loading and will not add considerable secondary plant.	In the next five years it is anticipated that 250 transformers will be replaced due to capacity issues.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 06/24/2019 **Date of Response: 07/09/2019**
Request No. OCA 2-054 **Page 1 of 2**
Request from: Office of Consumer Advocate

Witness: Amparo Nieto

Request:
Reference Nieto MCOS Direct at 11. Provide all jurisdictions that Witness Nieto is aware that include primary distribution system equipment in local distribution facilities cost. Provide orders with lines citation to support any claim.

Response:
In order to correctly assess marginal demand-related distribution costs, it is important to examine the specific distribution equipment driving these costs. The specific primary distribution equipment that Ms. Nieto is referring to on pages 10 and 11 (Bates stamp 1737, lines 13 to 21 and 1738 at lines 1 and 2) of her testimony are the local primary lines that are installed below the point where the trunkline feeder branches out. These local primary lines can be used to connect a primary customer directly to the grid and to feed secondary line transformers. A local primary line must be rated high enough to handle the installed kVa of all the transformers to be served by the line at the time load is added to the system. In other words, the design of these lines is tied to the design demand known at the time of installation of transformers. Because the local primary lines serve highly undiversified demand, they are considered part of the local facilities. These investments stay mostly fixed after the time of installation. They are planned using standard design demand considerations so that they do not need to change as actual demand grows over time, i.e., once primary lines are installed, they can seldom be changed.

A number of marginal cost studies for other utilities include local primary lines as a marginal distribution facility cost component. These costs are captured in the analysis as part of the equipment needed to connect customers to the grid or when conducting a primary line extension to connect a new customer. These are typically stated as dollar per kW of transformer or design demand of the customers, in a similar fashion as Ms. Nieto's MCOSS for PSNH. Below are several examples of utilities that utilize this approach, including reference to the respective cost of service witness' filed testimony that describes the approach.

Pacific Gas & Electric - PG&E differentiates between the investments in mainline primary distribution that occur to address load growth and the investments in primary lines incurred to add new (business) customers to the grid. Marginal primary distribution costs are estimated from investments made to extend primary distribution to new customers. PG&E measures peak capacity for these lines at the final line transformer (FLT). (PG&E, Application 16-06-013, 2017 General Rate Case Phase II, Exhibit PG&E-9, Volume 1 Marginal Costs).

NV Energy – NV Energy includes some primary lines as part of its distribution facilities marginal costs. See Direct Testimony of Jeff Bohrman filed as part of the Application of NEVADA POWER COMPANY, d/b/a NV Energy, pursuant to NRS 704.110 (3) and (4), addressing its annual revenue requirement for general rates charged to all classes of customers. Docket No. 17-06. On page 7, Q&A #9, Mr. Bohrman states: "Marginal facilities costs represent the costs of, and associated with, the Company's investment in distribution facilities installed for, and closest to, the customer. They include service drops, transformers, secondary distribution, and some primary distribution facilities, where appropriate."

New York State Electric & Gas (NYSEG) and Rochester Gas & Electric (RG&E) in 2015 Rate Case proceedings – See Ms. Nieto's 2015 Direct Testimony as part of the Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Case 15-E- ____ New York State Electric & Gas Corporation for Electric Service, filed May 20, 2015 (Ms. Nieto's testimony can be accessed at: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-g-0284&submit=Search).

Ms. Nieto's marginal cost studies for NYSEG and RG&E were used as the basis for NYSEG's and RG&E's proposed rate designs as part of their 2015 General Rate Case. The distribution facilities costs included local primary lines when included in the work orders reviewed. See, for example, Rebuttal Testimony of Revenue Allocation, Rate Design, Economic Development and Tariff Panel filed by the company, by expert witnesses: Patricia A. Beaudoin, Lori A. Cole, Mark O. Marini, Brian J. McNierney, Susan B. Morien, Joseph M. Rizzo, Carolyn A. Sweeney and James D. Simpson. (Case 15-E-0283; Case 15-G-0284; Case 15-E-0285; Case 15-G-0286). On page 20 of the Rebuttal testimony, lines 5-14, the testimony reads:

> " As stated in our Direct Testimony as well as the Direct Testimony of Company Witness Nieto, marginal costs have played a significant role for rate design purposes in the Companies' past rate cases, and the Commission has long recognized the use of marginal costs in the rate setting process. The Companies aim to reflect efficient price signals in all components of the rate, subject to achieving class revenue targets. For customer charges, the efficient price signal means recovering marginal customer costs, not embedded costs which are a measure of sunk costs. Marginal distribution facilities costs are also included in the marginal customer charge estimate. As a guide for setting monthly customer charge rates, the Companies relied on the results of the MCOS studies as shown in Table 16 of Company Witness Nieto's RG&E Direct Testimony and Table 17 of her Direct Testimony."

Ms. Nieto's marginal cost study was also filed by Avangrid on March 23, 2017 as part of its compliance filing with the Commission Order on Net Energy Metering Transition, Phase One of the Value of Distributed Energy Resources, and Related Matters, issued and effective March 9, 2017 in the above referenced proceedings, for New York State Electric & Gas Corporation and Rochester Gas and Electric.

Otter Tail Power Co. - OTP used Ms. Nieto's marginal cost study results in its rate design in Minnesota, North Dakota and South Dakota. The local facilities costs included local primary lines if needed to provide connection to new customers. For an example of OTP's testimony that discusses these facilities, please see Rate Design Direct Testimony of David Prazak, filed as part of OTP's Rate Application before the South Dakota PUC on April 20, 2018 (the testimony can be accessed here: https://www.otpco.com/media/2538/sd-rate-review_2b.pdf). On page 11 of such testimony, Mr. Prazak states the following: "Fixed charges can also recover the cost of connecting to the local distribution system, including the required transformers, secondary lines or local primary lines that may need to be added or expanded to accommodate the customer's expected maximum demand over the life of the facilities"