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

Date Request Received: 07/15/2019 **Date of Response: 07/29/2019**
Request No. OCA 3-002 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Troy Dixon, Eric H. Chung

Request:
If Eversource's step year adjustments were approved out to 2022, would this preclude it from filing another rate case until 2023?

Response:
No, approval of the Company's step adjustment proposal would not, in isolation, preclude the Company from filing another rate case until the conclusion of the step adjustment period. Many factors affect the timing of a rate case filing, and it would be speculative at this time to draw conclusions about the timing of the next rate case filing in the normal course of operations.

However, the Company would consider a stay-out provision that would preclude a rate filing in the context of a comprehensive settlement with terms that provide for GTEP investments and an adequate step adjustment mechanism being included in those terms. Over the next several years, the main cost drivers on the system will be capital investment and the cost of new information systems, and the Company's ability to avoid a base-rate filing is predicated on the ability to address those cost items that are the most direct cause of earnings attrition. In addition, the Company has a growing concern regarding the overall condition of the system and the need to accelerate investment to install overhead distribution facilities that have greater resiliency and can better accommodate clean energy technologies. If the Company is able to conclude this case with a supportive framework to enable the continued strengthening of distribution infrastructure and information systems backbone, the Company would find a stay-out provision an agreeable term of settlement.

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

Date Request Received: 08/13/2019 **Date of Response: 08/27/2019**
Request No. OCA 6-049 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Joseph A. Purington, Lee G. Lajoie

Request:
Reference Purington and Lajoie Testimony, Bates 428, Lines 9-10, describing the step adjustments and stating "[t]his proposal is similar to the approach allowed in the Company's 2009 rate case."

a. How many steps were approved in the Company's last rate case?
b. What percent of those annual capital investments did the Commission allow the company to recover via steps?
c. What percentage of annual O&M expenses did the Commission allow the Company to recover via steps, if any?

Response:
Below is the requested comparison. However, it should be noted that the Company's last base rate case was conducted approximately 10 years ago. Since that time, significant changes in the electric distribution industry have occurred (and are continuing to occur), requiring the Company to increase capital investment and to fund process initiatives that did not exist in the past. In addition, the Company is investing substantially in new processes and system automation that requires additional operating and maintenance procedures. As a result, on a collective basis, the Company is facing new challenges that would not have been experienced at the time of the last rate case. The Company's proposals in this case are designed to align with the actual cost pressures and investment requirements that currently exist.

The table below provides a comparison of the step adjustments in the current filing and the Company's 2009 rate case, understanding that the DE 09-035 step adjustment detail was part of a comprehensive settlement agreement that contained other aspects to the settlement than displayed below.

STEP ADJUSTMENT DETAIL	2009 RATE CASE DE 09-035	2019 RATE CASE DE 19-057
Number of Step Adjustments Approved/Proposed	3	4
Percent of Annual Capital Investments Allowed/Proposed	80% of Non-REP	100%
Percent of Annual O&M Expenses Allowed/Proposed	0%	.64%, starting in Step #2 *

* percent would increase to 1.92% if Enterprise IT Projects Depreciation is included

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

Date Request Received: 10/10/2019 **Date of Response: 10/24/2019**
Request No. STAFF 13-009 **Page 1 of 1**
Request from: **New Hampshire Public Utilities Commission Staff**

Witness: **Troy Dixon, Douglas P. Horton**

Request:
Reference Company response to OCA 6-45, in which the Company responds to a request for its base capital plan, which contemplates $135 million in investments annually through 2023, by directing the reader to Bates SFR-003970, which contains only two years of forecasted capital investments broken down into only four categories of distribution base capital investments. Please provide the detailed base capital plan used by the Company to determine the $135 million in investments it seeks within the step adjustments through 2023.

Response:
The Company's capital planning process begins with a high-level, long-range (5 year) capital expenditure and capital addition forecast by major category of investment developed in the spring timeframe of a given year. This 5 year forecast is also referred to as the strategic plan. Toward the end of the year, a detailed one-year capital expenditures plan at the specific project level is developed for the coming year and forms the basis of the Company's capital budget. This capital budget includes capital additions and cost of removal.

In this proceeding the Company has calculated illustrative step adjustments based on the capital expenditure forecast currently available which, for the out years is still at the major category level and is not yet developed at the specific project level detail that accompanies the one year plan. However, please note that the calculations included in this proceeding are for illustrative purposes. The Company is not at this time requesting that the PUC authorize the precise step adjustment in future years that has been calculated in this case. Here, the Company is requesting to implement step adjustments on a going forward basis that will be calculated based on actual plant placed in service through the end of the year prior to the year the step adjustment goes into rates.

The illustrative step adjustments provided in this rate case are estimated based on the high-level, long range capital addition forecast, which is produced by category of investment and not at a specific project level. However, a detailed plan for capital expenditures at the project level is available for 2019 and is provided in the Company's annual construction budget filing which was provided in SFR-001756 and Attachment OCA 1-009 F.

The base capital plan referenced in the Purington and Lajoie testimony is a subset of the total PSNH capital expenditures budget. OCA 6-045 asked for the 2019 base capital plan as referenced in the Purington and Lajoie testimony. Further detail about this base capital plan for 2019-2023 is provided in the strategic plan as provided in Attachment OCA 4-001, pages 83-107.

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

Date Request Received: 08/13/2019 **Date of Response: 08/27/2019**
Date Supplement Request Received: 10/29/2019 **Date of Supplement Response: 11/15/2019**
Request No. STAFF 9-025-SP01 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Penelope Conner

Request:
Reference Testimony of Penelope McLean Connor. Please provide the number of customer accounts coded as financial hardship as of July 31, 2019. Of those accounts, identify the number with balances great than $300 and more than 60 days past due. Please provide the total past due receivables associated with those accounts.

Response:
ORIGINAL RESPONSE:

The number of customers coded financial hardship as of July 31, 2019 is 25,570. Of those accounts, the number with balances greater than $300 and more than 60 days past due is 3,825. The total past due receivables associated with the 3,825 accounts is $5,325,656.42.

SUPPLEMENTAL RESPONSE:

The Company has verified that as of July 31, 2019 the number of customers that are coded financial hardship is 25,570, and the number of those accounts with balances greater than $300 and more than 60 days past due is 3,825. The total past due receivables associated with the 3,825 accounts is $5,325,656.42.

The coding for financial hardship and EAP are different in Eversource's C2 system. The vast majority of EAP customers have a financial hardship coding but not all financial hardship customers are EAP. STAFF 9-025 was not impacted by the under reporting of EAP customers due to the separate financial hardship coding.

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

Date Request Received: 08/13/2019 **Date of Response: 08/27/2019**
Request No. STAFF 9-023 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Penelope Conner

Request:
Reference Testimony of Penelope McLean Connor page 40 (Bates 778), lines 20-21. Please provide the basis for the estimate of 3,000 customers that would participate in the proposed New Start program. If customer interest exceeds that figure, is the company proposing that customer participation be capped at 3,000 customers?

Response:
In the Testimony of Penelope McLean Conner page 40 (Bates 778), lines 20-21 the basis for the estimate of 3,000 customers that would participate in the proposed New Start program is derived from comparing the size of the New Hampshire and Western Massachusetts service territories. In 2018 3,153 Western Massachusetts customers participated in the New Start program, the Company estimates that similar participation levels would be expected in New Hampshire.

The Company is not proposing that customer participation be capped if interest exceeds the 3,000 customer estimate. New Start would be offered to all interested residential customers that meet the program's eligibility criteria in an effort to help the customer eliminate past due balances and avoid disconnection.

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

Date Request Received: 08/13/2019 **Date of Response: 08/28/2019**
Request No. STAFF 9-020 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Penelope Conner

Request:
Reference Testimony of Penelope McLean Connor page 6 (Bates 744), line 11, and page 35 (Bates 773), lines 2-4. Please quantify how much the company spent in the test year on collection activities associated with accounts coded financial hardship and the projected decrease in collection activity expenses if the proposed New Start program is approved and implemented.

Response:
The Company's total actual collection related costs for the 2018 test year associated with handling delinquent accounts is provided in the table below. The Company does not separately track costs only associated with accounts coded as financial hardship.

Year	Actual NH Collection Costs
2018	$ 2,247,420

If the proposed New Start program is approved and implemented in NH, the projected decrease in collection activity expenses specifically related to New Start customers who would not be eligible for disconnect for non-payment would be as follows:

Estimated Annual Avoided Cost of Not Sending Disconnect Notices to New Start Customers (includes cost to print and mailing notices): **$9,000**
Estimated Annual Avoided Cost of Not Disconnecting New Start Customers (includes cost to disconnect / reconnect customers: **<u>$88,000</u>**
Total Annual Avoided Cost Associated with New Start Customers:
$97,000

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

Date Request Received: 10/10/2019 **Date of Response: 10/24/2019**
Request No. STAFF 13-012 **Page 1 of 2**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Charlotte Ancel, Kevin Boughan

Request:
Reference Company response to OCA 6-31(a), describing the business case for planned make-ready investments in electric vehicle supply equipment.

a. Please provide the live excel model supporting the attachment, including the basis for any assumptions used to develop the model.
b. Please explain why the discount rate is 7%, rather than the Company's Weighted Average Cost of Capital.
c. Please state whether the cost of the make-ready charging investments is included in the revenue requirements requested in the steps in this rate case. If so, please explain where and why such recovery has been requested.
d. Please state the level of usage assumed for the electric vehicle supply equipment and provide the basis for that assumption.
e. Please identify on the exhibits provided in the Chung/Dixon testimony the page and line that show the Company's capital investment and any other costs associated with the EV charging equipment. Please also identify where the investment and costs are included in the calculation of rates.

Response:
a. The live Excel model is provided as Attachment Staff 13-012.

The net benefits were calculated based on the increased sales to the system resulting from the proposed infrastructure.

The assumptions for increased sales and project capital investment can be found on the 'Increased Sales' tab in column E ('Assumption Notes')

b. For simplicity and illustrative purposes, the model used 7%. Had the model used a WACC of 7.61%, the resulting Benefit / Cost ratio would have been 1.12 vs. 1.17.

c. In this proceeding the Company has calculated illustrative step adjustments based on the capital expenditure forecast currently available. However, please note that the calculations included in this proceeding are for illustrative purposes. The Company is not at this time requesting that the PUC authorize the precise step adjustment in future years that has been calculated in this case. Here, the Company is requesting to implement step adjustments on a going forward basis that will be calculated based on actual plant placed in service through the end of the year prior to the year the step adjustment goes into rates.

The make-ready charging investments are anticipated to be implemented in the near term would therefore be included in the Company's requested steps in this rate case. These investments are considered part of the many base capital investments in the upcoming five years.

d. See part (a).

e. As stated in Part (c), these are considered part of the many base capital investments in the upcoming five years. This amount is not broken out specifically and is included with the other base capital investments.

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

Date Request Received: 08/13/2019
Request No. OCA 6-031
Request from: Office of Consumer Advocate

Date of Response: 08/28/2019
Page 1 of 1

Witness: Charlotte Ancel

Request:
Reference Purington and Lajoie Testimony, Bates 394 Line 16 through Bates 395 Line 7, describing the Company's EV fast charging project.

a. Please provide the latest business case or project documentation prepared by Eversource in anticipation of the EV fast charging network investment.
b. When would the "infrastructure to support future expansion of up to 40 additional DC fast chargers" would be used and useful for the purposes of cost recovery at the New Hampshire Public Utilities Commission?
c. What is the dollar value of the portion of the $2 million in make ready infrastructure that will actually be supporting a third party charger once it is made ready?
d. What is the dollar value of the portion of the $2 million in make-ready infrastructure that will support future expansion?
e. Is the Company building in idle infrastructure capacity with hope that an additional 40 DC fast chargers will be built in the future?

Response:

a. Please see Attachments OCA 6-031 A and B.

b. Eversource intends to work closely with customers to ensure they intend to install additional chargers in the reasonably near future. If the customer does not intend to install additional chargers in the near future (due to physical or other limitations) Eversource will limit the capacity of the make-ready infrastructure to chargers installed.

   The infrastructure to support future expansion of charging stations is necessary to avoid costly future excavation and upgrade work. Investments made in future chargers meet the criteria of reasonably foreseeable plant completion and based on projections of electric vehicle adoption.

c. In a scenario where 12 sites in Eversource territory are selected to receive funding for 4, 50kW DC Fast Chargers each from the VW Settlement D funding (chosen and administered by the State), approximately $1,670,000 be supporting the installed chargers.

d. In a scenario where 12 sites in Eversource territory are selected to receive funding for 4, 50kW DC Fast Chargers each from the VW Settlement D funding (chosen and administered by the State), and all 12 sites expressed intent and had physical ability to install additional chargers in the near future, approximately $442,000 total would be supporting the capacity to install those additional chargers.

e. Eversource intends to work closely with customers to ensure they intend to install additional chargers in the reasonably near future. If the customer does not intend to install additional chargers in the near future (due to physical or other limitations) Eversource will limit the capacity of the make-ready infrastructure to chargers installed.

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

Date Request Received: 08/13/2019 | **Date of Response: 08/27/2019**
Request No. OCA 6-110 | **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Edward A. Davis

Request:
Reference Davis Testimony, Bates 1820, Lines 17-20, stating "Regarding decoupling, the Company plans to continue its current decoupling mechanism to address prospective sales and revenue impacts of both energy efficiency and distributed generation," and NARUC's Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ) (2007) describing decoupling as "one of three major approaches to dealing with the throughput issue," and the other two as: (1) straight fixed variable rate design, and (2) lost revenue adjustment mechanisms. Please explain how the Company's lost revenue adjustment mechanism is a decoupling mechanism, rather than an alternative to decoupling.

Response:
The Company's lost revenue adjustment mechanism ("LRAM") is indeed a form of decoupling and has been accepted in several recent regulatory proceedings as such, as referenced in the testimony by Mr. Davis for both energy efficiency and alternate net metering dockets. A LRAM may also be referred to as a partial or "limited" decoupling mechanism, relative to a full decoupling, revenue decoupling or revenue per customer mechanism, or other partial decoupling mechanisms. The Company's LRAM is designed to remove the disincentive for energy efficiency and net metering facilities; addresses the so-called throughput issue; and represents a method accepted by the Commission for this purpose.

For additional details, please see the response to CENH 1-013.

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

Date Request Received: 08/01/2019 **Date of Response: 08/15/2019**
Request No. CENH 1-013 **Page 1 of 2**
Request from: Clean Energy New Hampshire

Witness: Edward A. Davis

Request:
Given that the LRAM only creates a surcharge for specific lost revenue, please explain how the Company believes continuing to use LRAM for energy efficiency and distributed generation rather than actual revenue decoupling is in the Company's customer's best interest?

Response:
Public policy initiatives supporting the broad adoption of energy efficiency measures and distributed energy resources are in the customer's best interest. PSNH recognizes and embraces this reality and has put forth a comprehensive filing in this case to further those beneficial customer interests. As explained below, the LRAM will further the interests of customers in the same manner as full revenue decoupling or other forms of decoupling.

The ratemaking challenge that arises in relation to these important public policy objectives is that the traditional cost-of-service model (using a historical test year) relied on the availability of sales volume growth between rate cases to sustain ongoing capital and O&M requirements of the utility. However, achievement of these important public policy goals has the opposite effect in that it eliminates sales growth between rate cases that historically has persisted in the absence of such successful programs. As a result, the more success that occurs in working toward the public policy objectives, the more difficult it becomes for a utility to sustain the revenues necessary to support operations without frequent base-rate proceedings.

Revenue decoupling is a ratemaking mechanism that is intended to remove the disincentive for the distribution company to support the effective deployment of energy efficiency or the interconnection of distributed generation. The LRAM achieves this same result.

Specifically, the Company's LRAM mechanisms are a form of revenue decoupling that function to replace lost revenue incorporated into the revenue requirement in the most recent rate case. The only difference between the two mechanisms is that, rather than truing a utility's revenue collections up to the revenue requirement set in the past rate case, it replaces revenues lost to the installation of energy efficiency measures and other public policy programs that cause sales volumes to decline. The amount of lost revenue recovered by the utility may or may not be exactly the same under either measure. However, the LRAM has the benefit of being directly tied to measures installed on the Company's system and is effective in generating adequate revenues to accomplish the "decoupling" of revenue collections from actual sales volumes. As a result, the LRAM is fully effective in eliminating any disincentive to hinder the progress of conservation initiatives in the customer interest, as demonstrated by PSNH's progress and organizational support for energy efficiency and distributed generation initiatives.

The Commission has recognized that application of the LRAM for such purposes is in the public interest. As indicated in response to CENH-1-012, the LRAM for energy efficiency is based on actual measures installed. Any Lost Base Revenue ("LBR") included in the LRAM is subject to review and approval by the Commission. In its decision in Docket No. DE 17-136, the Commission recognized that the currently applicable energy efficiency plan and associated settlement agreement - which includes and adopts LBR recovery by means of the LRAM - promote energy efficiency, reduce market barriers to energy efficiency investment and provide demand side management incentives. In approving this plan, the Commission found that both energy efficiency participants and non-participants will benefit from resulting increased energy efficiency, and that it is consistent with the public interest. With respect to distributed generation, the Commission found that the timely recovery of LBR using the LRAM is just and reasonable, and serves the public interest, as stated in its decision in DE 16-576.

Docket No. DE 19-057
Data Request OCA 6-031
Dated 8/13/2019
Attachment OCA 6-031 A
Page 1 of 1

Base Assumptions

Model Assumptions			
Project life	(Years)	25	
Year for rollout	(Years)	1	
All-In Rate	($/kWh)	$0.08	All-in rate of 16 cents minus 8 cents for supply & policy (wholesale energy + capacity, EE, RPS, etc.)
Chargers	(#)	48	
Total Sites	(locations)	12	
Chargers Per Site	(#)	4	
Open Hours Per Day	(hours)	16	
Available Charges	(per hour / per port)	2	
Total Charges Capacity	(charges / year)	560,640	
Annual NH Tourist Party-Trips*	(#)	4,700,000	
Party charges / trip	(#)	1	
Year 1 EV Trips	(%)	0.5%	
Year 1 EV Trips	(#)	23,500	
Year 1 EV Charges / Year	(#)	23,500	
Incremental EV Trips / Year	(%)	0.2%	

**http://www.deanrunyan.com/NHTravelImpacts/NHTravelImpacts.html*

Accounting Inputs		
Discount rate	(%)	7%
Inflation	(%)	2%
Months per year	(Months)	12

Cashflow Inputs

Total Project Capital	($)	$2,111,400
Capital Rec. Factor	(%)	8.46%
Cust. Annual Copay	($/kWh-yr)	$0

Benefit & Cost Inputs

	1	2	3	4	5	6	7	8	9	10	11	12
Benefits (Increased Sales)	$0	$1,233,792	$2,516,936	$3,850,912	$5,237,240	$6,677,481	$6,811,030	$6,947,251	$7,086,196	$7,227,920	$7,372,478	$7,519,928
Costs (Revenue Requirement)	$1,554,181	$2,782,806	$4,461,755	$6,107,257	$7,864,178	$6,021,830	$5,969,701	$5,790,789	$5,616,415	$5,445,759	$5,277,845	$5,111,599

	13	14	15	16	17	18	19	20	21	22	23	24	25
Benefits (Increased Sales)	$7,670,326	$7,823,733	$7,980,208	$8,139,812	$8,302,608	$8,468,660	$8,638,033	$8,810,794	$8,987,010	$7,333,400	$5,610,051	$3,814,835	$1,945,566
Costs (Revenue Requirement)	$4,946,002	$4,780,488	$4,614,973	$4,449,459	$4,283,946	$4,118,431	$3,952,917	$3,787,403	$3,623,513	$3,055,090	$2,441,637	$1,579,197	$770,957

Summary Results

Net Present Benefits	($)	($2,821,091)
Net Present Cost	($)	$2,405,503
Net Cust. Imp./(Benefit)	($)	($415,588)
BCR	**(Ratio)**	**1.17**

Base Assumptions

Model Assumptions			
Project life	(Years)	25	26
Year for rollout	(Years)	1	
All-In Rate	($/kWh)	$0.08	
Chargers	(#)	48	
Accounting Inputs			
Discount rate	(%)	7%	
Inflation	(%)	2%	
Months per year	(Months)	12	

Cashflow Inputs

Total Project Capital	($)	$2,111,400
Capital Rec. Factor	(%)	8.46%
Cust. Annual Copay	($/kWh-yr)	$0

Summary Results

Net Present Benefits	($)	($2,821,091)
Net Present Cost	($)	$2,405,503
Net Cust. Imp./(Benefit)	($)	($415,588)
BCR	**(Ratio)**	**1.17**

	Benefits	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	Value Stream	1	2	3	4	5	6	7	8	9	10	11	12	13
1	Increased Sales	$0	$47,000	$67,116	$88,018	$109,729	$132,273	$155,675	$179,961	$205,155	$231,286	$258,379	$286,464	$315,568
	Total Benefit	$0	$47,000	$67,116	$88,018	$109,729	$132,273	$155,675	$179,961	$205,155	$231,286	$258,379	$286,464	$315,568
	Costs													
	Rate Base	1	2	3	4	5	6	7	8	9	10	11	12	13
	Gross Plant	$1,055,700	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400
	Accumulated Depreciati	($55,952)	($111,904)	($167,856)	($223,808)	($279,761)	($335,713)	($391,665)	($447,617)	($503,569)	($559,521)	($615,473)	($671,425)	($727,377)
	Net Plant	$999,748	$1,999,496	$1,943,544	$1,887,592	$1,831,640	$1,775,687	$1,719,735	$1,663,783	$1,607,831	$1,551,879	$1,495,927	$1,439,975	$1,384,023
	ADIT	($6,345)	($32,701)	($55,930)	($76,275)	($93,943)	($109,143)	($122,052)	($132,851)	($143,303)	($153,749)	($164,202)	($174,648)	($185,100)
	Ending Rate Base	$993,403	$1,966,795	$1,887,614	$1,811,317	$1,737,696	$1,666,545	$1,597,683	$1,530,932	$1,464,528	$1,398,130	$1,331,725	$1,265,327	$1,198,922
	Revenue Requirement													
	Ret. On Rate Base Inc. Ta	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%
	Invest. Ret. Incl. Tax	$92,784	$183,699	$176,303	$169,177	$162,301	$155,655	$149,224	$142,989	$136,787	$130,585	$124,383	$118,182	$111,979
	Depreciation Expense	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952
	O&M	$300,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Revenue Requirement	$448,736	$239,651	$232,255	$225,129	$218,253	$211,607	$205,176	$198,941	$192,739	$186,537	$180,335	$174,134	$167,931
	Benefit/Cost Analysis													
	Non-Participating Customer Impact/(Benefit)													
	(Benefits)	$0	($47,000)	($67,116)	($88,018)	($109,729)	($132,273)	($155,675)	($179,961)	($205,155)	($231,286)	($258,379)	($286,464)	($315,568)
	Cost	$448,736	$239,651	$232,255	$225,129	$218,253	$211,607	$205,176	$198,941	$192,739	$186,537	$180,335	$174,134	$167,931
	Net Cust. Imp./(Benefit)	$448,736	$192,651	$165,139	$137,111	$108,524	$79,334	$49,500	$18,980	($12,416)	($44,748)	($78,044)	($112,330)	($147,637)
	Net Pres Imp./(Benefit)	**($415,588)**												

	Benefits	2031	2032	2033	2034	2035	2036	2037	2038				
	Value Stream	14	15	16	17	18	19	20	21	22	23	24	25
1	Increased Sales	$345,723	$376,957	$409,302	$442,791	$477,455	$513,329	$550,446	$588,843	$628,556	$669,621	$712,078	$755,966
	Total Benefit	$345,723	$376,957	$409,302	$442,791	$477,455	$513,329	$550,446	$588,843	$628,556	$669,621	$712,078	$755,966
	Costs												
	Rate Base	14	15	16	17	18	19	20	21	22	23	24	25
	Gross Plant	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400
	Accumulated Depreciati	($783,329)	($839,282)	($895,234)	($951,186)	($1,007,138)	($1,063,090)	($1,119,042)	($1,174,994)	($1,230,946)	($1,286,898)	($1,342,850)	($1,398,803)
	Net Plant	$1,328,071	$1,272,119	$1,216,166	$1,160,214	$1,104,262	$1,048,310	$992,358	$936,406	$880,454	$824,502	$768,550	$712,598
	ADIT	($195,547)	($205,999)	($216,446)	($226,898)	($237,344)	($247,797)	($258,243)	($255,826)	($240,540)	($225,254)	($209,968)	($194,682)
	Ending Rate Base	$1,132,524	$1,066,119	$999,721	$933,316	$866,918	$800,514	$734,115	$680,580	$639,914	$599,248	$558,582	$517,916
	Revenue Requirement												
	Ret. On Rate Base Inc. Ta	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%	9.34%
	Invest. Ret. Incl. Tax	$105,778	$99,576	$93,374	$87,172	$80,970	$74,768	$68,566	$63,566	$59,768	$55,970	$52,172	$48,373
	Depreciation Expense	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952
	O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Revenue Requirement	$161,730	$155,528	$149,326	$143,124	$136,922	$130,720	$124,518	$119,518	$115,720	$111,922	$108,124	$104,325
	Benefit/Cost Analysis												
	Non-Participating Customer Impact/(Benefit)												
	(Benefits)	($345,723)	($376,957)	($409,302)	($442,791)	($477,455)	($513,329)	($550,446)	($588,843)	($628,556)	($669,621)	($712,078)	($755,966)
	Cost	$161,730	$155,528	$149,326	$143,124	$136,922	$130,720	$124,518	$119,518	$115,720	$111,922	$108,124	$104,325
	Net Cust. Imp./(Benefit)	($183,993)	($221,429)	($259,976)	($299,667)	($340,533)	($382,608)	($425,928)	($469,325)	($512,836)	($557,700)	($603,955)	($651,640)

Model Assumptions			Assumption Notes
Project Life	(years)	26	Useful life of equipment
Total Sites	(locations)	12	Number of sites supported by VW investment in Eversource territory
Chargers Per Site	(#)	4	Number of chargers supported by VW investment in Eversource territory
Open Hours Per Day	(hours)	16	Best estimate
Available Charges	(per hour / per port)	2	Average 30 minutes per charge based on EvGo public statements
Total Charges Capacity	(charges / year)	560,640	Calculation (Chargers x Available Charges)
Annual NH Tourist Party-Trips	(#)	4,700,000	http://www.deanrunyan.com/NHTravelImpacts/NHTravelImpacts.html
Party charges / trip	(#)	1	Best estimate
Year 1 EV Trips	(%)	0.5%	Conservative estimate based on EV penetration in region
Year 1 EV Trips	(#)	23,500	Calculation (Trips x EV trip %)
Year 1 EV Charges / Year	(#)	23,500	Calculation (EV Trips x Charges / Trip)
Incremental EV Trips / Year	(%)	0.2%	Conservative estimate based on EV penetration growth in region
Inflation	(%)	2%	Best estimate
All In Rate	($/kWh)	$ 0.08	All-in rate of 16 cents minus 8 cents for supply & policy (wholesale energy + capacity, EE, RPS, etc.)
Utility Side Cost Per Site	($)	$ 79,000.00	Utility estimate of component costs (primary lateral feed, tranx / pad, meter)
Customer Side Cost Per Site	($)	$ 96,950.00	Based on contractor estimate
Total Utility Capital Investment	($)	########## ##	Calculation (Total sites x Utility + Customer side costs)

Year	1	2	3	4	5	6	7	8	9	10	11	12	13
Chargers	0	48	48	48	48	48	48	48	48	48	48	48	48
EV Trips		23,500	32,900	42,300	51,700	61,100	70,500	79,900	89,300	98,700	108,100	117,500	126,900
EV Charges		23,500	32,900	42,300	51,700	61,100	70,500	79,900	89,300	98,700	108,100	117,500	126,900
Incremental Sales (kWh)		587,500	822,500	1,057,500	1,292,500	1,527,500	1,762,500	1,997,500	2,232,500	2,467,500	2,702,500	2,937,500	3,172,500
Effective Rate	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10
Revenue	$ -	$ 47,000	$ 67,116	$ 88,018	$ 109,729	$ 132,273	$ 155,675	$ 179,961	$ 205,155	$ 231,286	$ 258,379	$ 286,464	$ 315,568

Year	14	15	16	17	18	19	20	21	22	23	24	25
Chargers	48	48	48	48	48	48	48	48	48	48	48	48
EV Trips	136,300	145,700	155,100	164,500	173,900	183,300	192,700	202,100	211,500	220,900	230,300	239,700
EV Charges	136,300	145,700	155,100	164,500	173,900	183,300	192,700	202,100	211,500	220,900	230,300	239,700
Incremental Sales (kWh)	3,407,500	3,642,500	3,877,500	4,112,500	4,347,500	4,582,500	4,817,500	5,052,500	5,287,500	5,522,500	5,757,500	5,992,500
Effective Rate	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.13
Revenue	$ 345,723	$ 376,957	$ 409,302	$ 442,791	$ 477,455	$ 513,329	$ 550,446	$ 588,843	$ 628,556	$ 669,621	$ 712,078	$ 755,966

Description	1	2	3	4	5	6	7	8	9	10	11	12	13
Tax Dep													
Investment	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400
MACRS 20-Yr	4%	7%	7%	6%	6%	5%	5%	5%	4%	4%	4%	4%	4%
Tax Dep Expense	$79,178	$152,422	$140,978	$130,421	$120,624	$111,587	$103,205	$95,478	$94,211	$94,190	$94,211	$94,190	$94,211
Accumulated Dep.	$79,178	$231,599	$372,578	$502,999	$623,623	$735,211	$838,416	$933,893	$1,028,104	$1,122,294	$1,216,504	$1,310,694	$1,404,904
Book Dep													
Investment	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400
Book Dep.	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
Book Dep Expense	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952
Accumulated Dep.	$55,952	$111,904	$167,856	$223,808	$279,761	$335,713	$391,665	$447,617	$503,569	$559,521	$615,473	$671,425	$727,377
ADIT													
Excess Tax over Boo	($23,225)	($119,695)	($204,721)	($279,190)	($343,863)	($399,498)	($446,751)	($486,277)	($524,535)	($562,773)	($601,031)	($639,269)	($677,527)
Composite Tax Rate	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%
ADIT	($6,345)	($32,701)	($55,930)	($76,275)	($93,943)	($109,143)	($122,052)	($132,851)	($143,303)	($153,749)	($164,202)	($174,648)	($185,100)

Description	14	15	16	17	18	19	20	21	22	23	24	25
Tax Dep												
Investment	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400
MACRS 20-Yr	4%	4%	4%	4%	4%	4%	4%	2%	0%	0%	0%	0%
Tax Dep Expense	$94,190	$94,211	$94,190	$94,211	$94,190	$94,211	$94,190	$47,105	$0	$0	$0	$0
Accumulated Dep.	$1,499,094	$1,593,305	$1,687,494	$1,781,705	$1,875,894	$1,970,105	$2,064,295	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400
Book Dep												
Investment	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400	$2,111,400
Book Dep.	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
Book Dep Expense	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952	$55,952
Accumulated Dep.	$783,329	$839,282	$895,234	$951,186	$1,007,138	$1,063,090	$1,119,042	$1,174,994	$1,230,946	$1,286,898	$1,342,850	$1,398,803
ADIT												
Excess Tax over Boo	($715,765)	($754,023)	($792,261)	($830,519)	($868,757)	($907,015)	($945,253)	($936,406)	($880,454)	($824,502)	($768,550)	($712,598)
Composite Tax Rate	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%	27.32%
ADIT	($195,547)	($205,999)	($216,446)	($226,898)	($237,344)	($247,797)	($258,243)	($255,826)	($240,540)	($225,254)	($209,968)	($194,682)

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

Date Request Received: 08/13/2019 **Date of Response: 09/03/2019**
Request No. OCA 6-087 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Penelope Conner

Request:
Reference McLean Conner Testimony, Bates 785, Lines 7-9, stating "the AMR option deployed by the Company in 2013 was a solution that was fully and substantially cost justified as a basis for transitioning away from manual meter reading."

a. Please explain whether the Company's AMR meters are capable offering customers a time of use rate and why.
b. Please explain the expected useful life of the Company's existing meters.

Response:

A. The standard AMR meter used in New Hampshire is not capable of measuring Time of Use KWH. The AMR meters strictly measure total usage for the billing period. There is a Time of Use meter in use in New Hampshire for TOU customers. AMR meters are not used for capturing interval data.

B. It is expected that the AMR meters will have a 20 to 25 year life in practice. This assumption is based partially on the the fact that the manufacturers' information for bridge meters is that the non-replaceable battery installed in the meter (demand and remote disconnect meters) will have a 20-year life. The standard AMR meter does not have a battery, so the expected life of the meter is not dependent on battery life.