STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 19-057

REQUEST FOR PERMANENT RATES

DIRECT TESTIMONY OF

ERIC H. CHUNG AND TROY M. DIXON

Revenue Requirements

On behalf of Public Service Company of New Hampshire
d/b/a Eversource Energy

May 28, 2019

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PETITION OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY REQUEST FOR PERMANENT RATES

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I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Eric H. Chung. I am employed by Eversource Energy Service Company as Director, Revenue Requirements (New Hampshire) and Regulatory Projects. My business address is 247 Station Drive, Westwood, Massachusetts 02090.

Q. What are your principal responsibilities in this position?

A. I am currently responsible for all regulatory activity affecting the financial requirements of Public Service Company of New Hampshire ("PSNH" or the "Company"). I am also responsible for certain enterprise-wide regulatory initiatives for the Eversource Energy operating businesses in the states of Connecticut, Massachusetts and New Hampshire.

Q. Please summarize your professional experience.

A. I was appointed to my current position in February 2015. From August 2013 to January 2015, I was Director of Revenue Requirements for the Eversource Energy operating companies in Massachusetts and New Hampshire, including PSNH.

Prior to joining Eversource, from 2011 to 2013, I was a Senior Manager in the Power Utilities Advisory practice at Ernst and Young LLP. From 2009 to 2011, I worked for PacifiCorp, a vertically-integrated electric utility serving approximately 1.7 million customers across six states in the Western United States, where my primary role was Director of Environmental Policy and Strategy. I also served as an Associate Partner in the Utilities practice at Oliver Wyman, a Senior Engagement Manager in the Power practice at Strategic Decisions Group, and a Senior Programmer Analyst at Goldman Sachs. I have over 20 years of relevant management consulting and industry experience, with most of my career dedicated to the power and utilities sectors.

Q. Please summarize your educational background.

A. I received a Bachelor of Arts degree in physics with honors from Harvard College, as well as a Master of Business Administration in finance and economics from the University of Chicago Booth School of Business.

Q. Have you previously testified before the New Hampshire Public Utilities Commission?

A. Yes, I have previously testified before the New Hampshire Public Utilities Commission (the "Commission") in many proceedings, including Docket No. DE 11-250 (Investigation of Merrimack Station Scrubber Project and Cost Recovery); Docket No. DE 13-274 (2014 Stranded Cost Recovery Charge Rate Change); Docket No. DE 13-275 (2014 Default Energy Service Rate Change); Docket No. DE 13-108 (Reconciliation of Energy Service and Stranded Costs for Calendar Year 2012); Docket DE 14-238 (2015 Public Service Company of New Hampshire Restructuring and Rate Stabilization Agreement); Docket No. DE 15-464 (Lease Agreement Between Public Service Company of New Hampshire and Northern Pass Transmission); Docket No. DE 16-693 (Public Service Company of New Hampshire Power Purchase Agreement with Hydro-Renewable Resources); Docket No. DE 17-096 (Petition for Finding of Fact and Issuance of Financial Order); Docket No. DE 17-105 (Sale of Wyman 4 Interest); and Docket No. DE 17-124 (sale of generating assets).

Q. Mr. Dixon, please state your name, position and business address.

A. My name is Troy M. Dixon and I am employed by Eversource Energy Service Company as the Director of Revenue Requirements. My business address is 107 Selden Street, Berlin, Connecticut 06037.

Q. What are your principal responsibilities in this position?

A. As Director of Revenue Requirements, I am responsible for the preparation and presentation of distribution rate cases and various other regulatory filings.

Q. Please summarize your professional experience.

A. In 2003, I accepted a position with Aquarion Water Company of Connecticut ("AWC-CT") as Regulatory Compliance Specialist. Through 2009, I worked for AWC-CT in various roles with increasing responsibility. In October 2009, I was promoted to Director of Rates and Regulation for AWC-CT where I was responsible for the preparation and presentation of distribution rate cases and other various regulatory filings. In March 2018, I transitioned to my current position.

Q. Please summarize your educational background.

A. I received a Bachelor of Arts Degree in economics and accounting from the College of the Holy Cross in Worcester, Massachusetts. I also have a Master of Business Administration from the New York University Stern School of Business.

Q. Have you previously testified before the Commission?

A. Yes, I have previously testified before the Commission in various proceedings for Aquarion Water Company of New Hampshire ("AWC-NH") in Dockets DW 08-098 and DW 12-085, which were the most recent rate cases for AWC-NH. I also testified in Dockets DW 10-293, DW 11-238, DW 12-325, DW 13-314, DW 14-300, and DW 16-828, which were Water Infrastructure and Conservation Adjustment filings for AWC-NH.

Q. What is the purpose of your testimony?

A. Our testimony provides the revenue-requirement calculation and existing revenue deficiency for PSNH. We are submitting this testimony regarding PSNH's distribution revenue requirement in support of PSNH's request that the Commission approve new permanent distribution rates effective July 1, 2020. On April 26, 2019, we also filed separate testimony in support of PSNH's request for temporary rates effective July 1, 2019.

Our testimony also provides support for several other ratemaking proposals, which are: (1) the Company's proposal to recover the cost of its proposed Fee Free Program through base rates; (2) the Company's proposal for post-test year Step Adjustments to recover the additional revenue requirements associated with significant post-test year capital investments; and (3) implementation of a new distribution recovery adjustment mechanism to recover the costs associated with five programs. The five programs and associated cost recovery include: (a) a redesigned Major Storm Cost Recovery ("MSCR") mechanism that would reconcile annual storm cost above or below the level set in base rates; (b) a Vegetation Management Program reconciling mechanism; (c) a Regulatory Reconciliation Adjustment mechanism; (d) the "New Start" Arrearage Forgiveness Program; and (e) the Grid Transformation and Enablement Program ("GTEP"). The GTEP would provide post-rate case support for capital expenditures, undertaken to accelerate capital work targeted at upgrading the condition of the distribution system for resiliency and the integration of advanced clean energy technologies, and for two demonstration projects designed to provide important learning opportunities as the Company prepares to meet customer demand for increased system integration of clean energy technologies in the future.

Q. Are you presenting any Attachments in support of your testimony?

A. Yes, we are presenting the following Attachments in support of the Company's filing:

Exhibit Designation	Schedule Designation	Purpose/Description
Attachment EHC/TMD-1 (Perm)	Schedules EHC/TMD-1 (Perm) through EHC/TMD-41 (Perm)	Computation of Revenue Requirement
Attachment EHC/TMD-2 (Perm)	Schedules EHC/TMD-1 (Perm) through EHC/TMD-12 (Perm)	Lead Lag Study Analysis
Attachment EHC/TMD-3 (Perm)		Computation of Illustrative Step Adjustments
Attachment EHC/TMD-4 (Perm)		Five-Year Storm Average Costs
Attachment EHC/TMD-5 (Perm)		Net Benefits Analysis
Attachment EHC/TMD-6 (Perm)		Proportional Share of Merger Savings
Attachment EHC/TMD-7 (Perm)		Merger-related O&M savings
Attachment EHC/TMD-8 (Perm)	Schedules EHC/TMD-1 (Perm) through EHC/TMD-3 (Perm)	Excess Accumulated Deferred Income Taxes
Attachment EHC/TMD-9 (Perm)	Schedules EHC/TMD-1 (Perm) through EHC/TMD-4 (Perm)	Illustrative GTEP Revenue Requirement

Q. Has PSNH submitted other documentation as required by Puc 1604?

A. Yes. The documentation required by Puc 1604 is included with this filing in a separate volume.

Q. How is your testimony organized?

A. Our testimony is organized into the following sections:

- **Section I** - provides the introduction to our testimony.
- **Section II** - provides an overview of the revenue requirement analysis.

- **Section III** – provides a comprehensive discussion of the Company's calculation of the test year revenue requirement, including a discussion of the normalizations and adjustments to test year operating expenses, depreciation, amortization of deferred assets, and tax issues.
- **Section IV** – describes the Company's computations of Rate Base and Rate of Return.
- **Section V** – summarizes the Lead Lag analysis.
- **Section VI** – presents the Company's proposal for post-test year Step Adjustments.
- **Section VII** – presents the Company's calculations of Excess Accumulated Deferred Income Taxes ("EDIT").
- **Section VIII** – presents the Company's proposal for a new distribution cost recovery mechanism.
- **Section IX** – provides the conclusion to our testimony.

II. SUMMARY OF REVENUE REQUIREMENTS ANALYSIS

Q. What is the test year period that PSNH used for the revenue requirement analyses presented in this case?

A. The test year is the 12-month period ending December 31, 2018 ("Test Year").

Q. What is the "Rate Year" in this this case?

A. The term "Rate Year" for purposes of this permanent rate case filing refers to the first 12 months during which the rates established in this proceeding will be in effect (July 1, 2020 to June 30, 2021). The Company is also proposing to implement four annual Step

Adjustments to base rates to recover the revenue requirement associated with capital investments and certain information systems infrastructure expense changes in 2019 ("Investment Year 1"), 2020 ("Investment Year 2"), 2021 ("Investment Year 3"), and 2022 ("Investment Year 4") (collectively the "Investment Years"). The proposed Step Adjustments would be effective July 1, 2020 to June 30, 2021 ("Step Year 1"); July 1, 2021 to June 30, 2022 ("Step Year 2"); July 1, 2022 to June 30, 2023 ("Step Year 3"); and July 1, 2023 to June 30, 2024 ("Step Year 4").[1]

Q. Would you please summarize the PSNH distribution cost of service and resulting revenue requirement?

A. Yes. Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-3 (Perm) presents the revenue-requirement summary for PSNH, computing a total cost of service of $436,202,680. For the Test Year, the calculated distribution revenue deficiency is $69,912,696, based on adjusted Test Year revenues of $366,289,983. The computation of the PSNH revenue deficiency reflects total adjusted rate base of $1,215,667,897 and assumes a weighted average cost of capital of 7.62 percent as supported by the testimony of Company Witness Ann E. Bulkley of Concentric Energy Advisors, Inc.

As noted above, in addition to the permanent base rate increase, the Company is seeking approval to implement four annual Step Adjustments to recover the revenue requirement

[1] The costs for Investment Year 1 (2019) would be recovered in Step Year 1; the costs for Investment Year 2 (2020) would be recovered in Step Year 2; the costs for Investment Year 3 (2021) would be recovered in Step Year 3; and the costs for Investment Year 4 (2022) would be recovered in Step Year 4.

associated with significant capital investments and certain discrete expenses between 2019 and 2022. Without annual revenue Step Adjustments, the Company will under-earn when permanent rates go into effect. As shown in Attachment EHC/TMD-3 (Perm), the illustrative revenue requirements presented for the Step Adjustments for the four Investment Years are as follows:

Total Estimated Revenue Requirement Investment Years 2019 - 2022			
Investment Year 1 (2019)	**Investment Year 2 (2020)**	**Investment Year 3 (2021)**	**Investment Year 4 (2022)**
$15 million	$21 million	$14 million	$16 million

The revenue requirement amounts presented in the table above are illustrative based on current estimates of plant additions and expenses in the Investment Years. The actual annual step adjustments that will go into effect on July 1 annually 2020 through 2023 will be calculated based on actual plant additions and expenses in the prior Investment Year. The Company's proposal for post-Test Year Step Adjustments is presented in full detail in Section VI below.

Q. Did the Company make any normalizing or post-test year adjustments to the cost of service in this filing?

A. Yes. To identify the appropriate normalizing and post-test year adjustments to test year revenues or expenses, the Company first reviewed the Test Year activity to identify any cost or revenue elements that are non-recurring, out-of-period, or otherwise not appropriate to be reflected in the revenue requirement. Similarly, to the extent that the Test Year excludes certain known and measurable cost or revenue changes that will be incurred on a continuing basis, those elements are appropriate for inclusion in the revenue requirement. Where the Company has identified such elements, it has reflected the elements as normalizing adjustments to the cost of service in this filing to establish a "normalized" revenue requirement from which to make pro-forma or post-Test Year adjustments.

Q. Please describe the process for identifying normalizing adjustments.

A. In order to remove out-of-period or non-recurring items from the Test Year level of expense activity, the Company performed a detailed review of account activity to normalize out-of-period or non-recurring activity. As a supplement to this review, the Company's Accounting Department identified any accounting entries that were recorded on PSNH's books that were "out-of-period," meaning the entries were booked during the Test Year but are related to a different time period. In addition, the Company's Accounting Department identified entries that were recorded outside of the 12-month test year but that should have been recorded within the Test Year. This exercise has resulted in the Company's proposal for an adjusted Test Year that is reflected in the various schedules of Attachment EHC/TMD-1 (Perm). All of the normalizing adjustments in the Company's permanent rate filing and described below are consistent with those made in the April 26, 2019 temporary rate filing.

Q. Did the Company make any normalizing adjustments to Test Year Operating Revenues?

A. Yes. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 1, line 21, Column (E), the Company made normalizing adjustments to operating revenues totaling $13,289,292. The largest normalizing adjustment reflected in this amount is related to the accrued regulatory liability associated with the 2017 Tax Cuts and Jobs Act ("TCJA"). As discussed in the Company's temporary rate filing, the accrued regulatory liability associated with the TCJA is equal to $12,276,000. The accrued regulatory liability was recorded as a reduction to revenues during the Test Year. Because new rates resulting from this case will reflect currently prevailing income tax rates, the Company will cease to accrue this regulatory liability after new rates are set. Therefore, the Company has made this normalizing adjustment to its recorded Test Year revenues to reverse the effect of this accounting treatment during the Test Year. This normalizing adjustment increases the level of per-book revenues recorded during the Test Year, which has the effect of lowering the revenue deficiency and requested rate increase in this proceeding.

Q. Did the Company make any normalizing adjustments to Test Year Operating and Maintenance Expenses?

A. Yes. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 1, line 29, Column (E), the Company made adjustments to operations and maintenance ("O&M") expenses totaling $17,941,149 to reflect a number of increases and decreases to operating expenses, but principally to account for a $16,800,000 increase associated with the reclassification of Enhanced Tree Trimming ("ETT"), Hazard Tree Removal, and right-of-way clearing costs as O&M expense consistent with annual amounts approved by the Commission for the 2019 Reliability Enhancement Program ("REP") in Docket No. DE 18-177.

Q. Did the Company make any normalizing adjustments to Test Year Other Operating Expenses?

A. Yes. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 1, line 33, Column (E), the Company made adjustments to amortizations totaling $14,746,439 to reflect certain increases and decreases to Other Operating Expenses. The primary driver of this total is a $15,512,608 increase to account for the amortization of deferred storm costs related to events through 2018.

Q. Did the Company make any normalizing adjustments to Test Year Taxes Other than Income?

A. Yes. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 1, line 38, Column (E), the Company made normalization adjustments totaling $3,120,992 to reflect a number of increases and decreases to Other Operating Expenses. The primary driver of this total is a $3,058,417 increase to account for the 2018 decision of the Supreme Court of New Hampshire ("Supreme Court") upholding a tax abatement on PSNH property, which is described in more detail below.

Q. Please describe the indirect cost reallocation included in Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 1, Column (C).

A. The indirect cost reallocation in Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 1, Column (C) is a two-step process designed to provide a more simplified cost of service presentation by aligning net credits for capitalization with total direct costs from PSNH and total allocated costs from Eversource Energy Service Company related to the following six cost of service expense adjustments: (1) Employee Benefits; (2) Insurance; (3) Payroll Taxes; (4) Enterprise IT Projects Expense; (5) Enterprise IT Projects Depreciation; and (6) Lease Expense.

The first step is to reverse in total the Test Year activity recorded using cost elements ZPB (Payroll Benefit Loader) and ZGS (General Service Company Benefit Loader). The second step is to develop composite Test Year capitalization percentages for PSNH and Eversource Energy Service Company in order that the ZPB and ZGS indirect costs will follow where the actual test year PSNH and Eversource Energy Service Company employee labor was charged (i.e., either O&M or capital). When the total Test Year PSNH direct costs and Eversource Energy Service Company allocated costs (for the six expense items listed above) are multiplied by these capitalization percentages, it aligns credits for capitalization with the precise accounts where Test Year labor is charged.

As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 1, line 49, Column (C), the net effect of this reallocation on the cost of service for ratemaking purposes is zero. In short, the Company performed the indirect cost allocation to better align capitalization credits with total direct costs to provide a more transparent presentation of the cost of service.

Q. Have you computed rate base for purposes of the revenue requirement analysis?

A. Yes. The Company has calculated rate base incorporating plant in service through December 31, 2018. The rate-base computation is summarized in Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-36 (Perm).

Q. The Company's filing encompasses other rate-related proposals. Do these proposals affect the computation of the revenue requirement?

A. Most of the new rate-related proposals presented by the Company in this proceeding do not affect the base distribution revenue requirement computation, because PSNH is proposing to recover the costs associated with the majority of these proposals outside of base rates through a new distribution recovery adjustment mechanism ("DRAM"). We discuss the DRAM in more detail in Section VIII below. The Company is also proposing to continue the Lost Base Revenue ("LBR") Adjustment mechanism already in place to recover lost revenues associated with energy efficiency programs and investments. The Company's LBR proposal does not affect the computation of the revenue requirement or the revenue deficiency in this case and is discussed in more detail in the testimony of Company Witness Edward A. Davis.

Alternatively, the Company is proposing to collect the costs of its proposed Fee Free Program through base rates. More specifically, the Company is proposing to recover a four-year estimate of costs, net of offsetting savings, through base rates. Due to the uncertainty in the timing or magnitude of customer utilization of credit/debit cards without an associated fee for doing so, the Company cannot incorporate the cost of the Fee Free Program into base rates as a typical known and measurable post-Test Year adjustment to base rates. As a result, the Company is proposing to incorporate an estimate of costs into base rates, and any actual expenses that exceed or are below the amount included in base rates will be deferred for future credit or recovery. We discuss the adjustment to the revenue requirement to account for this program in Section III below. The details of the Fee Free Program are discussed in the testimony of Company Witness Penelope McLean-Conner.

Q. Does PSNH's cost of service include costs incurred by a centralized service company on behalf of PSNH?

A. Yes. In the Test Year, service company charges were billed to PSNH by Eversource Energy Service Company.

Q. Please explain the service company structure during the Test Year.

A. Beginning with the effective date of the merger of Northeast Utilities and NSTAR, April 10, 2012, Northeast Utilities Service Company ("NUSCO") and NSTAR Electric & Gas Service Company ("NE&G") operated as a single service company organization despite being separate legal entities. Effective January 1, 2014, NE&G was legally merged into NUSCO, with NUSCO as the surviving entity. Effective February 2, 2015, Northeast Utilities and all of its subsidiaries began doing business as Eversource Energy, and NUSCO was renamed as Eversource Energy Service Company.

Eversource Energy Service Company provides administrative, corporate, and management services to PSNH and other operating subsidiaries of Eversource Energy. The cost of service for PSNH reflects charges from Eversource Energy Service Company in the Test Year.

Q. How are Eversource Energy Service Company costs incorporated into the PSNH revenue requirement calculations?

A. Eversource Energy Service Company charges to PSNH are recorded on the PSNH books and then incorporated into the appropriate expense categories used in the cost of service. Service-company charges fall into two categories: (1) "direct charges" billed for costs incurred and work performed by service-company personnel directly related to PSNH; and (2) "common costs" that are allocated among the respective subsidiaries receiving service based on the appropriate allocation factors.

Q. Are charges billed to PSNH in conformance with a service agreement?

A. Yes. During the Test Year, there were operating agreements in effect between Eversource Energy Service Company and PSNH. These agreements identify the services that are provided to PSNH and reference the billing methods that are applied to calculate the charges presented each month to PSNH.

Q. Does PSNH's cost of service include costs associated with the generation business recently divested by the Company?

A. There are no costs in the distribution cost of service in the Test Year associated with the New Hampshire electric generation business, which was divested in 2018. In anticipation of the completion of the divestiture, and the use of 2018 as a Test Year, pro rata corporate allocations from the generation business were no longer allocated to PSNH Distribution as of January 1, 2018. Additionally, no transaction costs related to the electric generation divestiture are contained in the Test Year or pro forma cost of service.

Q. Is there any other analysis that you have relied upon to prepare the PSNH revenue requirement?

A. Yes. We have used the recommended cost of capital presented by Company Witness Ann E. Bulkley from Concentric Energy Advisors, Inc. to compute the PNSH revenue requirement. The PSNH revenue requirement also includes depreciation expense derived from the depreciation studies prepared by Company Witness John J. Spanos of Gannett Fleming Valuation and Rate Consultants, LLC. Lastly, the revenue requirement also relies on the results of the working capital Lead Lag study performed by the Company in support of this proceeding and described later in this testimony.

III. REVENUE REQUIREMENTS ANALYSIS

Q. What post-test year adjustments have you made to PSNH's revenue requirements calculation?

A. The PSNH revenue requirement includes post-Test year adjustments to Operating Revenues, O&M and Administrative and General ("A&G") Expenses, Depreciation, Amortization, and Taxes. We discuss the revenue requirement analysis and specific adjustments in the subsections that follow.

A. Operating Revenues

Q. Which schedules show the adjustment to Operating Revenues?

A. Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-4 (Perm), page 1 shows the Test Year revenue per books in Column (B). Non-distribution revenues of ($694,676,467) that were recognized in the Test Year as distribution revenue have been removed from Test Year revenues as shown in Column (C). More specifically, as shown in lines 27 through 32, Column (C), the non-distribution revenues of ($603,842,286) that have been removed from the Test Year are recovered through other reconciling rate mechanisms established by the Commission, including transmission, Energy Efficiency, retail, electric assistance program, and Energy Service. Other Revenues shown in lines 38 through 44, Column (C) totaling ($90,834,181) were also removed from Test Year revenues. Adjustments to account for the TCJA benefit and other revenues are shown in Column (E). Lastly, adjusted Test Year revenues are shown in Column (F).

Q. Please describe in more detail how the adjusted Test Year amount on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-4 (Perm), page 1, Column (E) is derived.

A. As shown on Schedule EHC/TMD-4 (Perm), page 1, line 24, Column (E), the Company has included $23,000 related to an adjustment to reflect billed retail revenue at the January 1, 2018 distribution rate level for the entire Test Year and a streetlighting revenue adjustment related to an out of period adjustment during the year. The other adjustments to operating revenues are principally to account for the TCJA credit in the amount of $12,276,000 (line 39), described previously, and a $999,432 (line 40) normalizing adjustment to account for certain late payment charges in the Test Year.

With respect to the TCJA adjustment, in Docket No. DE 18-049 the Company proposed to address the TCJA-related accrued refunds due to customers in the context of the Company's 2019 base-rate case.[2] The Company's temporary rate filing set that process in motion, so that PSNH customers can realize the benefits of the tax savings beginning with the effective date of temporary rates on July 1, 2019.[3]

In Docket No. DE 18-049, the Company estimated a monthly tax benefit due to the change in the tax gross-up of $1.023 million, which is equivalent to the annualized amount of $12.3 million.[4] This amount was recorded in the Test Year as a reduction in revenues, but needs to be added back to revenues going forward because new distribution rates will properly reflect changes in Federal and State tax rates that were effective as of January 1, 2018. Accordingly, as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-4 (Perm), page 1, line 39, Column (E) the Company has increased its revenues and lowered

[2] *See* March 30, 2018 Technical Statement of Christopher J. Goulding, Bates Pages 3-4, in Docket No. DE 18-049.

[3] *See* Order No. 26,177 (Sept. 27, 2018) at 1 (directing the Company to "address the rate effects of the tax reductions by March 31, 2019, and request a rate for effect July 1, 2019, that is designed to provide customers with the full benefit of the tax reductions when Eversource files its certification of 2018 Exogenous Events, if, by that time, Eversource has not already done so in a rate case filing.").

[4] *See* March 30, 2018 Technical Statement of Christopher J. Goulding, Attachment CJG-1, Bates Page 5, in Docket No. DE 18-049.

its revenue deficiency to reverse the annual credit associated with the total TCJA benefit amount of $12.3 million.

The $999,423 adjustment relates to the Commission's suspension of the Company's ability to collect late-payment charges from customers who pay their bills by mail in Docket No. DE 17-171.[5] After making the transition to a payment processing vendor located in Boston, Massachusetts, the Company made a filing on December 13, 2018, requesting an amendment to its tariff to reinstitute late payment charges. On January 24, 2019, the Commission approved the Company's proposed tariff changes.[6] Therefore, the Company included a normalizing adjustment to increase Test Year revenues in the amount of $999,432 to reflect a representative amount that would have been billed for late charges in the Test Year, calculated using a historical, three-year average. This has the effect of lowering the revenue deficiency associated with the temporary rate request in this proceeding by the same amount.

Q. Please describe in more detail how the pro forma adjustments on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-4 (Perm), page 1, Column (G) are derived.

A. The Company has included in other revenues: (1) $608,221 in miscellaneous service revenues, as detailed further on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-4 (Perm), page 2, Column (D); and (2) $59,526 in additional Rent from Electric Property as

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5 *See* Order No. 26,110 (March 7, 2018).

6 Secretary Letter Approving Tariff Changes, Docket No. DE 17-171 (Jan. 24, 2019).

detailed on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-4 (Perm), page 3, Column (D).

Q. Please elaborate on the adjustments to Miscellaneous Service Revenues.

A. The increase in Miscellaneous Service Revenues of $608,221 is detailed on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-4 (Perm), page 2. As shown therein, there are five underlying adjustments to update decade-old fees to reflect the current costs of customer-service related charges:

- An increase of $119,493 to reflect updated Reconnection and Reactivation Fees that are charged when the Company first establishes or re-establishes a Delivery Service account for a customer at a meter location.

- An increase of $337,318 to reflect updated service fees related to dispatching a Company employee to a customer location to collect a delinquent bill when necessary.

- An increase of $1,172 to reflect updated service fees for Rate Maintenance and Error Correction provided by the Company in support of Billing and Payment Service to Suppliers.

- An increase of $18,490 to reflect updated Meter Diversion Fees that are levied when interference with the proper registration of an electric service meter has been established.

- An increase of $131,748 to reflect updated Returned Check Fees that are levied when a customer makes a payment to the Company for service with a check or draft that is not accepted by the institution on which it is written.

Q. Please elaborate on the adjustments to Rent from Electric Property.

A. The increase in Rent from Electric Property of $59,526 is detailed on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-4 (Perm), page 3.

As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-4 (Perm), page 3, line 21, Column (D), the adjustment is driven primarily by an increase of $75,823 in Pole Attachment Fees to reflect the most up-to-date pole attachment rates. Pursuant to Puc 1300 and R.S.A. 374:34-a, the Company charges third-parties (e.g., telecommunications companies, cable providers, etc.) fees to attach to the Company's utility poles in accordance with pole attachment agreements entered into between the Company and third-party pole attachers. Each pole attachment agreement contains a section on fees and specifies that attachment fees are updated annually.

As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-4 (Perm), page 3, lines 23, 25, 27, 31, and 33, Column (D), the remainder of the Rent from Electric Property adjustment is a reduction of ($16,928) reflecting updated rates related to lease revenue received from third-party use of Eversource property and facilities. The specific adjustments making up this ($16,928) reduction are as follows:

- An increase in rent revenues of $1,111 relating to a land lease for a fiber optics shelter located in Manchester, New Hampshire. These facilities are owned by PSNH, which charges rent to Crown Castle Fiber for the use of the property. This increase reflects the most up to date costs to be charged to Crown Castle Fiber.

- An increase in rent revenues of $1,969 relating to a lease for a parcel of land owned by PSNH, which allows Sprint Nextel (the lessee) to utilize a communications tower owned by the Company. This increase reflects the most up to date costs to be charged to Sprint Nextel.

- An increase in rent revenues of $1,838 relating to a lease for a parcel of land owned by PSNH, which allows T-Mobile (the lessee) to utilize a communications tower owned by the Company. This increase reflects the most up to date costs to be charged to T-Mobile.

- An increase in rent revenues of $2,567 relating to a lease which allows Northeast Optical Network to occupy space in an underground fiber optics duct. This increase reflects the most up to date costs to be charged to Northeast Optical Network.

- A decrease of ($23,783) relating to leases for floor space located at Eversource's Westwood, Massachusetts office.

B. Adjustments to Test Year O&M Expense

Q. What is the amount of per-book Test Year O&M Expense?

A. In the Test Year, PSNH incurred $588,239,267 in O&M expense as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 3, line 85, Column (C).

Q. Has the Company removed non-distribution expenses, such as those associated with purchased power and transmission?

A. Yes. The Company conducted a rigorous process to identify and remove non-base distribution expenses. First, the Company matched total Test Year expenses per books to the equivalent expenses by account reflected on pages 320-323 in the FERC Form 1 Report. Those audited expense balances, totaling $588,239,267, are the starting point for the adjustment calculation and are shown on Schedule EHC/TMD-5 (Perm), page 5, Column C. Next, as shown on Schedule EHC/TMD-5 (Perm), page 5, line 85, Column N, the Company identified $438,263,245 related to non-base distribution expenses recovered through other rate mechanisms established by the Commission including default service, energy efficiency, electric assistance program, transmission, and generation charges. Then, the Company adjusted the Test Year by removing the non-base distribution expenses of $438,263,245 as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 3 Column (D) for an adjusted Test Year expense of $149,976,022.

Q. Did the Company make any other adjustments to the Test Year level of expenses?

A. Yes. In order to account for out-of-period or non-recurring items from the Test Year level of expense, the Company undertook a detailed review of account activity to normalize out-of-period or non-recurring activity. The normalizing adjustments reflected in the permanent rate filing and described below are the same as those included in the Company's temporary rate filing submitted on April 26, 2019 for effect July 1, 2019.

Q. Please describe the normalizing adjustments to O&M Expense presented on Schedule EHC/TMD-5 (Perm), page 2.

A. The normalizing adjustments presented on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 2, line 45, Column (E), result in a net increase to Test Year O&M Expense of $17,941,149. This net increase is primarily driven by one item, which is a $16,800,000 adjustment associated with the reclassification of ETT, Hazard Tree Removal, and right-of-way clearing costs as O&M expense.

Q. Please provide more detail with respect to the adjustment to account for vegetation-management expense.

A. In Docket No. DE 17-196, the Commission examined the Company's accounting treatment for vegetation management costs in the REP in 2018, which covered ETT, hazard tree removal, and full-width right-of-way clearing. The Commission approved a change to discontinue the accounting practice of recording these costs as capital and to treat such costs as O&M expense beginning in 2019.[7]

In Docket No. DE 18-177, the Commission authorized the continuation of the Company's REP for calendar year 2019 in a manner that accounted for certain changes in vegetation

[7] Order No. 26,112 (March 12, 2018) at 3, 5.

maintenance activities and the continuation of the Company's Troubleshooter program. As described therein, the Company estimated the continuation of the vegetation management activities in the REP to require an incremental annual revenue requirement of $16,800,000 in 2019.[8] As approved, that deficiency was to be deferred until July 1, 2019, and was to be offset by a portion of the customer tax deferral to mitigate any rate change at that time.[9] As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-20 (Perm), page 2, line 33, Column (C), the Company has adjusted O&M expenses by $16,800,000 to account for the reclassification of vegetation-management costs from capital to O&M expense.

In addition, as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-20 (Perm), page 2, line 22, Column (C), the Company made an adjustment of $1,213,743 to account for tree-trimming maintenance services that the Company performs on behalf of a third-party pole owner. These services are critical to maintain the reliability of the electric distribution system. The amount of $1,213,743 is an actual expense incurred in the Test Year and represents the balance of billings to the third-party pole owner that currently remain unpaid.

Q. Please describe any other significant normalizing adjustments that were made to O&M Expense.

A. The Company made an additional normalizing adjustment to O&M Expense as itemized

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[8] *See* November 16, 2018 Technical Statement of Christopher J. Goulding, Bates page 10, in Docket No. DE 18-177.

[9] *See* Order No. 26,206 (December 28, 2018) at 4-5.

on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 6. The principal adjustments are summarized as follows:

- As shown on Attachment EHC/TMD-1 (Temp), Schedule EHC/TMD-5 (Temp), page 6, line 75, the Company made an adjustment of ($724,870) to reduce expenses to reflect actual amounts invoiced by the Commission for Fiscal Year ("FY") 2019 regulatory assessments. More specifically the reduction of ($724,870) reflects the difference between the amount booked for regulatory assessments in the Test Year of $5,501,189 and the actual invoiced amount in FY 2019 of $4,776,319. During the course of this proceeding, the Company expects to receive updated regulatory assessments from the Commission—with the next invoice expected in August 2019—and will update its revenue requirement accordingly to reflect this known and measurable change.

- As shown on Attachment EHC/TMD-1 (Temp), Schedule EHC/TMD-5 (Temp), page 6, line 62, the Company made an adjustment of ($760,111) to reduce expenses to remove certain non-recurring consulting costs for which the Company is not requesting recovery in this proceeding.

- As shown on Attachment EHC/TMD-1 (Temp), Schedule EHC/TMD-5 (Temp), page 6, line 54, the Company made a normalizing adjustment of $547,623 to account for a credit related to Test Year employee overhead expenses. Specifically, the Company uses a historical rate (developed based on prior year actual experience) to allocate non-productive time (i.e., vacation, sick time, jury duty, etc.) to where an employee's productive time was charged (e.g., O&M, capital, etc.). Since the rate used to allocate non-productive time was based on historical data, it did not match the actual Test Year non-productive amounts. The discrepancy caused by using a historical rate versus actual activity caused a net credit in Account 920 in the amount of ($547,623). In order to resolve this discrepancy, the Company is adding back this net credit as a normalizing adjustment to bring the Test Year balance in this account back to zero, or what a normal Test Year would reflect.

- As shown on Attachment EHC/TMD-1 (Temp), Schedule EHC/TMD-5 (Temp), page 6, line 77, the Company made an adjustment of $351,238 to reclassify interest charged on customer deposits from FERC Account 431 to FERC Account 930. Customer deposits are shown as a liability on a utility's balance sheet and represent a source of non-investor supplied capital. As explained in the NARUC Rate Case and Audit Manual ("NARUC Manual"), customer deposits are generally treated in one of three ways:

> The first method does not reduce rate base by the customer deposits balance and classifies any interest accrued or paid on those deposits as a below-the-line (or non-operating) expense.
>
> The second method reduces rate base by the customer deposits balance, and classifies any interest accrued or paid on those deposits as an above-the-line (or operating) expense that is included in the revenue requirement computation.

> The third method includes the liability for customer deposits in the utility's capital structure at a zero cost, reducing the overall rate of return.[10]

The Company employs the second method described in the NARUC Manual. Therefore, the adjustment in the amount of $351,238 is necessary to reflect the fact that the Company reduces rate base by the customer deposits balance, and classifies any interest accrued or paid on those deposits as an expense that is included in the revenue requirement.

- As shown on Attachment EHCTMD-1 (Temp), Schedule EHC/TMD-5 (Temp), page 6, line 48, the Company made an adjustment of $315,000 to add back out-of-period (2017) customer service costs—meaning the entry was booked during the Test Year but related to a different time period. The Company's Accounting Department identified this adjustment as part of its comprehensive review of accounting entries recorded on PSNH's books.

Q. Are there any other normalizing adjustments to the Company's O&M expenses?

A. Yes. Our testimony describes the more significant adjustments to O&M; however, all of the O&M adjustments are shown on Attachment EHC/TMD-1, Schedule EHC/TMD-5, pages 2 through 6.

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[10] *Rate Case and Audit Manual*, NARUC Staff Subcommittee on Accounting and Finance at 21 (2003), *available at* http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/NARUC_Rate_Case_and.pdf.

C. Post-Test Year Expense Adjustments

1. Postage Expense

Q. Did you adjust the Test Year Postage Expense for ratemaking purposes?

A. Yes. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-6 (Perm), page 2, line 20, the Test Year amount for postage expense is $1,929,795. An increase in the cost of first-class postage of 1.34 percent took effect on January 21, 2018. The Company has included a normalizing adjustment to reflect this increase. The result of this adjustment is an increase of $1,417, resulting in an adjusted Test Year amount of $1,931,212 for postage expense as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-6 (Perm), page 2, line 20.

Another increase in the cost of first-class postage of 1.32 percent took effect on January 27, 2019. The Company has included a post-Test Year adjustment to reflect this increase. The result of this adjustment is an increase of $25,545, as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-6 (Perm), page 2.

2. Information Services Expense

Q. Please describe the Information Services Expense Adjustment.

A. The $324,807 adjustment shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-7 (Perm), page 1, is required to account for increased post-Test Year expenses for Information Technology ("IT") administration and support as well as Telecommunications services provided to the Company by outside vendors. The $324,807 pro forma adjustment reflects higher vendor costs mirroring inflation, plus negotiated contractual increases as well as the overall support of new services and equipment. A more detailed breakdown of the Information Services Expense Adjustment is provided on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-7 (Perm), page 2.

3. Uncollectible Accounts

Q. Did you adjust the Test Year Uncollectible Expense?

A. Yes. The Company made a $1,042,852 adjustment related to bad-debt expense as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-8 (Perm). Specifically, to calculate this adjustment we calculated the average retail revenues and net write-offs for each of the past three years, including the Test Year, i.e., 2016 through 2018, as shown in Attachment EHC/TMD-1 (Perm), Workpaper EHC/TMD-8 (Perm). Net write-offs comprise the actual customer accounts written off for non-payment minus recoveries related to previously written off account balances. The resulting ratio of actual customer account write-offs to retail revenues is 0.6571 percent as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-8 (Perm), page 2, line 23, Column (B). This net write-off ratio is intended to represent the portion of the Company's billed revenues that it will ultimately be unable to collect from its customers. The total Test Year retail revenue of $953,681,402 is then multiplied by the net write-off ratio to arrive at a restated total company Test Year uncollectibles amount of $6,266,640 as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-8 (Perm), page 2, line 27, Column (B).

Using the allocation methodology approved in Docket No. DE 09-035, this restated Test Year total is then allocated 52.3 percent to distribution (or $3,277,054), and 47.7 percent to energy service (or $2,989,586), based on the ratio of Test Year distribution revenues to the sum of Test Year distribution revenues and Test Year energy service revenues.[11] The difference between the recomputed Test Year pro forma level of bad debt expense of $3,277,054 and the Test Year balance in Account 904 (Uncollectible Accounts) of $2,234,202 results in a pro forma increase of $1,042,852 in bad-debt expense, as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-8 (Perm), page 1, line 23, Column (C). In brief, this increase is driven by the application of the approved allocation methodology described above.

4. <u>Fee Free Payment Processing</u>

Q. Have you included an adjustment to incorporate costs associated with fee free payment processing for residential customers?

A. Yes. Today, customers who opt to pay their bills with a credit or debit card are required to pay a $2.25 transaction fee directly to the Company's third-party payment processing agent. This is described in detail by Company Witness Penelope M. Conner, who also discusses the fact that customers are dissatisfied when required to pay a "convenience" fee for credit and debit card payments. To align the Company's service offerings with customer experience in the broader marketplace and improve customer satisfaction, the

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[11] Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-8 (Perm), page 2, lines 35 through 37).

Company is proposing to implement a "fee free" credit/debit card payment option.

To provide these transactions on a least-cost basis, the Company conducted a competitive solicitation process in advance of this rate case and negotiated a contract with the winning bidder, subject to the Commission's review and acceptance of the Company's associated ratemaking proposal in this proceeding. The Request for Proposal ("RFP") process and resulting negotiations are described in detail in the testimony of Ms. Penelope M. Conner. We have incorporated an adjustment to reflect the cost of the credit/debit card processing fees in the distribution revenue requirement, rather than continuing to offer this payment option at a fee to residential customers.

Q. Please describe the adjustment for the Fee Free program.

A. The Company cannot offer or conduct credit/debit payment transactions without a third-party vendor to handle the actual transaction. Therefore, the Company conducted an RFP process designed to obtain the least-cost transaction fee for credit/debit card transactions to be handled by a third-party vendor. In this proceeding, the Company is presenting the results of this RFP, which produced a proposed agreement between Eversource Energy Service Company and SpeedPay Inc. ("SPI"), a subsidiary of Western Union, and requesting that the Commission allow recovery of the cost of this agreement through distribution rates. The agreement is presented with the testimony of Ms. Conner.

Under the Speedpay Agreement, SPI would provide the services necessary to offer credit/debit card transactions to PSNH residential customers on a "fee free" basis. The cost of the service will be charged to the Company, and the Company proposes to recover this cost from all customers through distribution rates. With the Commission's approval of the "fee free" proposal, the transaction fee for individual customers would be eliminated and the service would be available to all residential PSNH customers on a "fee free" basis. The cost for the Company would be a per transaction amount subject to change over the term of the agreement, depending upon specified parameters relating to the dollar value and number of transactions completed.

As discussed in Ms. Conner's testimony, based on reasonable assumptions regarding customer migration to the "fee free" credit/debit payment option, the total cost over the next four years is estimated to be $2,950,604 or $737,651 per year on average. The Company has also estimated that there will be offsetting cost savings associated with this program totaling $123,536 or $30,887 per year on average. The total net cost of the program is estimated to be $2,827,058 or approximately $706,764 per year on average.

As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-9 (Perm), the Company is proposing to include the $706,764 estimated average annual program cost in the revenue requirement. However, the amount actually paid to SPI by the Company will vary from year to year, with the actual amount paid by the Company remaining a function of actual customer migration and the value of the credit/debit transactions.

Q. What is the Company's ratemaking proposal relating to the "fee free" payment processing adjustment?

A. The testimony of Ms. Conner discusses the Company's expectations regarding residential customer participation in the "fee free" credit/debit card payment option. Due to the potential for the usage of credit and debit cards for payment to increase with the elimination of the "convenience" fee, the Company is proposing a transitional ratemaking treatment allowing for the adjustment of the annual amount included in rates in this case based on actual experience, whether positive or negative.

Annually, the actual amounts paid by the Company to SPI under the contract would be charged against a reserve fund, so that the balance of the fund represents the difference (plus or minus) between the amount collected in base rates and the amounts actually paid to SPI over the contract term. At the time of the Company's next base-rate proceeding, any over- or under-collection would be amortized into rates. Eventually, the annual cost of the "fee free" credit/debit card payment option will be suitable for routine incorporation into rates as a representative annual expense. However, the migration trend is expected to be so steep over the initial transition period that a different ratemaking approach is necessary to enable the transition. This proposal is designed to provide customers with the full benefit of the lowest cost per transaction, while also providing appropriate ratemaking treatment for transitioning these costs into base rates in the future, once they reach a steady state and representative level.

5. Employee Benefit Costs

Q. What adjustment has the Company made for employee benefit expense?

A. The post-Test Year adjustment made on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-12 (Perm), page 1 is an increase of $2,516,451. Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-12 (Perm), page 2, summarizes the pro-forma adjustments related to employee-benefit expense.

Q. Please describe how you determined the adjustment for employee-benefit expense.

A. There are three categories of adjustments associated with employee benefits: (1) medical/prescription, vision, and dental expense; (2) the 401K Savings Plan; and (3) Pension. These categories are discussed with additional detail as follows:

Medical, Dental, and Vision – Eversource Energy is self-insured for its healthcare benefits for active employees. Therefore, in order to determine the amount of the healthcare benefit expense to include in the revenue requirement for the Rate Year, it was necessary to apply an appropriate benefit-expense rate per employee to a representative number of employees for PSNH, as well as to Eversource Energy Service Company employees. In order to complete that analysis, we obtained the 2019 medical, dental, and vision "working rates" from the Eversource Human Resources Department. The working rates are provided to the Company by its external benefits consultants and represent the per employee expected claims levels for the following year. The working rates are utilized to determine the amount of contributions required by employees. We applied the per employee rates to the actual staffing levels and benefits plan participation at PSNH as of December 31, 2018. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC-12 (Perm), page 2, the Company then computed a pro forma adjustment, based on the benefit cost per employee using current full-time equivalent ("FTEs") levels and post-Test Year incremental FTEs that are in the process of being hired by the Company combined with updated 2019 working rates.[12] These incremental FTEs are discussed in more detail in the Payroll Expense section below.

The analysis presented on Attachment EHC/TMD-1 (Perm), Workpaper EHC/TMD-12 (Perm), page 2 supports the Test Year pro forma level of medical expense of $7,605,751; vision expense of $36,103; and dental expense of $346,279.

401K Savings Plan – The Company's 401K Savings Plan expense represents the company-match contributions to a defined contribution retirement plan. To determine the expense amount for the Rate Year, we multiplied the adjusted Test Year expense amount of $2,332,601 shown in Attachment EHC/TMD-1 (Perm), Schedule EHC-12 (Perm), page 2, at line 24, Column (F) by the Payroll Percentage Adjustment of 8.069 percent, resulting in a $188,219 pro forma adjustment. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC-12 (Perm), page 2, line 24, Column (I), the Company then computed a pro forma adjustment of $15,828 to account for post-Test Year incremental FTEs that are in

[12] As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC-12 (Perm), page 2, $434,717 of the pro forma adjustment for medical, dental and vision is driven by the current employee population while only $51,294 is associated with incremental post-Test Year FTEs.

the process of being hired by the Company. These incremental FTEs are discussed in more detail in the Payroll Expense section below.

Pension – The Company's pension plan is a closed plan—meaning no new employees are being added to the plan. The Company's pension expense is calculated in accordance with accounting standards that are designed to require consistent measurement and recognition of pension obligations and assets among reporting companies. The expense is based on an actuarial valuation that determines the Company's liability to each pension plan participant, and includes assumptions on salary increases, discount rate, and expected long-term rate of return on assets.

Eversource Energy Service Company employs the actuarial services of Aon plc ("Aon") in determining projected pension expense. Based on projections provided Aon, the pro forma pension expense adjustment is an increase of $1,581,235 as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC-12 (Perm), page 2, line 27, Column (G). The change in pension expense is driven by three factors: (1) normal operation of the plan; (2) lower actual 2018 asset returns of -1.3 percent versus the long-term expected return on assets of 8.25 percent; and (3) an increase of 68 basis points in the discount rate from 3.75 percent to 4.43 percent.[13]

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[13] The discount rate assumption is impacted by interest rate changes and it generally changes from year to year although the direction and magnitude of those changes are difficult to predict. For 2019, the yield curve approach utilized by Aon resulted in a weighted average discount rate of 4.43 percent.

6. Insurance Expense and Injuries & Damages

Q. What adjustment have you made for Insurance Expense and Injuries & Damages deductibles?

A. The post-Test Year adjustment made on Attachment EHC/TMD-1 (Perm), Schedule EHC-13 (Perm), page 1, shows an increase of $108,288 for Insurance Expense and Injuries & Damages. The net increase is detailed in Attachment EHC/TMD-1 (Perm), Schedule EHC-13 (Perm), page 2 and is driven primarily by an increase in premiums for Excess Liability insurance.

Q. Please describe the PSNH corporate insurance for property and liability coverage.

A. Property and liability coverage include several categories of insurance that provide protection from property loss, general liability and other damages that PSNH may incur in the conduct of its business. Eversource Energy Service Company manages the corporate insurance program through which PSNH secures insurance coverage. The corporate insurance program includes both premium-based and self-insured coverage in order to obtain the most cost-effective loss protection.

Q. How does Eversource Energy Service Company manage its liability insurance costs?

A. All insurance programs and policies are evaluated annually with the aid of insurance brokers in order to secure the best available coverage at the best available rate. To balance the risk mitigation that insurance provides and the level of premium costs, an appropriate level of self-insurance deductible is negotiated with insurance carriers. Higher deductible levels result in lower insurance premiums while also resulting in a higher retention of risk of loss. It is the balance between the two that Eversource Energy Service Company must manage on behalf of PSNH and the other operating companies that it serves.

Eversource Energy Service Company utilizes a well-accepted process when procuring insurance programs. In order to achieve the optimal coverage at the best cost, Eversource Energy Service Company utilizes its brokers to facilitate this process. The broker compiles the market submission and works with various insurance markets to solicit quotes for insuring the Eversource Energy Service Company program.

Approximately three to four months prior to the renewal date of the program, Eversource Energy Service Company's Insurance team holds a strategy meeting with the broker to discuss the current coverage in place, opportunities for improvement in coverage and upcoming renewal requirements, and strategies for presenting risk mitigation requirements to the market to optimize the coverage Eversource Energy Service Company has in place for the utility subsidiaries it serves, including PSNH.

Eversource Energy Service Company participates in various industry groups to stay abreast of insurance issues and trends including working groups within Edison Electric Institute and American Gas Association. Eversource Energy Service Company's Insurance group also maintains knowledge of key company initiatives that lower the Company's risk profile, helping to ensure the underwriting process goes smoothly. In addition to this information, and to the industry trend information provided by the broker, Eversource Energy Service Company also utilizes independent sources such as Edison Electric

Institute and other insurance surveys to evaluate market trends.

On a combined basis, these processes assist in assuring that the Company's corporate liability costs are as reasonable as possible.

Q. How are the pro forma adjustments related to insurance coverage calculated?

A. To determine the appropriate level of insurance expense to be included in the revenue requirement, we obtained the most recent insurance policies entered into by Eversource Energy Service Company. We were then provided with the portions of the premium of each policy that applied to PSNH. The resulting premiums form the basis of the insurance expense included in the revenue requirement. The prepayment of these costs is recorded and amortized over the appropriate fiscal period.

Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-13 (Perm) and Workpaper EHC/TMD-13 (Perm) provide the cost detail on these expenses for each of the underlying policies. Should the level of insurance expense change based on updated premiums during the pendency of this proceeding, the Company will file an updated revenue requirement to reflect this known and measurable change.

7. Payroll Expense

Q. What is included in the Company's payroll expense?

A. The Company's payroll expense includes its base and overtime payroll as well as PSNH's share of base and overtime payroll for Eversource Energy Service Company employees.

Q. Did the Company need to make adjustments to the Test Year to account for new hires?

A. Yes. As of the end of the Test Year, the Company hired additional union and non-union[14] employees. Therefore, because the employees hired during the Test Year were not reflected in the cost of service on an annualized basis, we made an adjustment to annualize the cost of labor during the Test Year to reflect the annualized level of labor for these new hires in the revenue requirement. As shown on Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-14 (Perm), page 2, in computing this annualization of costs, we took into account a scheduled union wage increase of 3 percent on June 4, 2018 and a non-union increase of 3 percent on April 1, 2018.

Q. Please provide more detail with respect to PSNH's new hires during the Test Year.

A. The Company created the New Hampshire Distribution System Operations Center ("DSOC") in 2015 with 10 Distribution System Operators ("DSOs"), 2 Supervisors and 1 Manager that oversee both the DSOC and the Troubleshooter organization. The initial duties of the DSOs were limited primarily to outage dispatch functions. The DSOs utilized the legacy mainframe Trouble Reporting System ("TRS") and Trouble Analysis System ("TAS") to monitor and dispatch crews. Prior to the creation of the DSOC, crews were dispatched by local management at the Area Work Centers ("AWCs") during the day and

[14] Eversource Energy Service Company employees are predominantly non-union employees and are included in these amounts.

by the call center after hours.

In the third quarter of 2015, the Company installed a new Oracle-based Outage Management System ("OMS") which allowed PSNH to implement a new way of managing trouble events and in the first quarter of 2016, 6 DSOs were added to support these new trouble event management responsibilities.

In 2017, the Company implemented a new electric system controllership model placing the ownership of all mainline circuitry with the DSOC instead of with the local AWCs and the call center. Contemporaneous with the controllership changes, the 4kV and 12 kV systems continued to be upgraded with automated devices to allow for remote operation with Supervisory Control and Data Acquisition ("SCADA") at the DSOC. In order to appropriately staff the new controllership model and manage the increased responsibility to operate and restore the system remotely, the Company added an additional 8 DSOs and 1 Supervisor in 2018, bringing the total number of DSOs to 24, the total number of Supervisors to 3, and 1 Manager.

Since 2015, the DSOs' duties have changed from simple dispatch functions to remote system operation and restoration of the distribution system, down to the 4 kV and 12 kV level. All outage events are now centrally managed and controlled through the DSOC, whether the outage occurs during a normal blue-sky day or during a large weather event on gray or black sky day situations. All planned work within the controllership of the DSOC on the system is managed by the DSOC, as well as fire and police outage trouble dispatch functions such as motor vehicle accidents and structure fire response. The DSOC manages the daily requirements of the system, maintains situational awareness and operation of the electric system, and manages the technology platforms used to control the system and the management of outage restoration. The current staffing level of operators also allows for the inclusion of a training week in the schedule. Training is critical to provide the skills required to safely and reliably operate the electric system, respond accordingly to emergency situations (Fire and Police dispatchable events), and provide the proper guidance to field workers responding to outages.

Q. Have you made post-Test Year adjustments for payroll expense?

A. Yes. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-14 (Perm), page 1, line 23, Column (C), the post-Test Year adjustment increases O&M payroll by $4,673,452 which reflects the annualization of new hires during the Test Year, adjustments to account for known and measurable increases to union and non-union payroll, and the addition of incremental FTEs in the Rate Year. The details of this adjustment are shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-14 (Perm), page 2 and the accompanying workpapers.

Q. How did the Company develop its projections for payroll expenses?

A. We examined the adjusted Test Year payroll amounts to determine whether these amounts would continue to be the same in the Rate Year, or whether any known and measurable changes would occur. We determined that changes would occur in terms of both new incremental FTEs and scheduled wage increases taking place in 2019 and 2020.

Q. How did the Company develop its union and non-union payroll expense projections?

A. The majority of PSNH union employees are covered by a single collective bargaining agreement between the Company and the International Brotherhood of Electrical Workers ("IBEW") Local 1837. A 3 percent union wage increase will take effect on June 2, 2019 during this case.[15] This known and measurable change has been included in the projection to compute the payroll-union adjustment of $1,655,081 shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-14 (Perm), page 2, line 54, Column (B). With respect to non-union employees, 3 percent wage increases are reflected for April 1, 2019 and April 1, 2020 to compute the non-union payroll adjustment of $3,017,772 shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-14 (Perm), page 2, line 54, Column (C). These wage adjustments reflect all the known and measurable payroll adjustments that will be occurring prior to the midpoint of the Rate Year, or before January 1, 2021.

Q. Please explain the incremental post-Test Year FTEs the Company is requesting.

A. The payroll increase reflects 5 new incremental FTEs at PSNH and PSNH's allocated share of 14 new Information Technology ("IT") FTEs which are being hired by Eversource Energy Service Company. The 5 PSNH employees are needed to support the Company's Expanded Troubleshooters Program. The additional 14 IT FTEs are needed for a cyber

[15] The collective bargaining agreement currently in place is set to expire in May 2020. The Company has addressed additional post-Test Year union wage increases as part of its Step Adjustment proposal discussed in more detail in Section VI below.

security initiative to defend against cyber threats to the critical infrastructure of the Company and will allow for advanced security monitoring and operations support of the Company's systems.

Q. What employees are needed for the Expanded Troubleshooters Program? [16]

A. In 2015, the Company created the Troubleshooter organization to dedicate a single-person first responder for most outage events with coverage 24 hours per day, 7 days per week, and 365 days per year. The primary coverage areas for the 18 Troubleshooters and 2 Supervisors that initially staffed the organization was the Central and Southern regions, encompassing the Hooksett, Bedford, Derry, and Nashua area work centers. Six Troubleshooters were located in each of the Hookset, Bedford and Nashua area work centers. The Troubleshooters are fully-qualified Class I lineworkers that operate as a single person crew utilizing a fully equipped material handling line truck. When Troubleshooters are not working on emergent trouble work, they perform scheduled work consisting of customer work (temporary to permanent service installs, meter float work, service and primary rubber cover work), substation inspections, circuit reliability patrols, and National Electric Safety Code ("NESC") underground and transformer padmount inspections.

In 2018, the Company expanded the coverage area for the Troubleshooter organization to include the Eastern and Western regions, encompassing the Rochester, Epping,

[16] The Troubleshooter organization is also discussed in detail in Part I of the Grid Transformation and Enablement Program testimony sponsored by Company Witnesses Purington and Lajoie.

Portsmouth, Keene and Newport area work centers. To support this expanded coverage area, as well as the need for additional coverage in the Southern/Central region, the Company expanded the Troubleshooter organization by an additional 14 FTEs (34 total FTEs). The additional 14 FTEs consist of 12 Troubleshooters, 1 Supervisor, and 1 Manager. The 12 Troubleshooters break down as follows: 4 troubleshooters in the Western region; 4 Troubleshooters in the Eastern region; and 4 Troubleshooters in the Central/Southern region. At the end of the Test Year, 8 Troubleshooters and 1 Supervisor were hired to partially staff the Troubleshooter organization (14 FTE fully staffed). To fully staff the Troubleshooter organization, the Company hired 1 additional Manager in January 2019 and 1 additional Troubleshooter in February 2019 and expects to hire 3 more Troubleshooters in 2019 (i.e., 5 incremental FTEs).

The Troubleshooters shift coverage in the Eastern and Western regions is 7 days per week, 12 hours per day from 6am to 6pm. The additional Troubleshooters in the Central/Southern region work a 3pm to 11pm shift schedule Monday through Friday to allow for additional second shift coverage. The expansion of the program into the Eastern and Western regions and enhancement in the Central/Southern region provides quicker response to trouble calls during and after work hours and provides for a more efficient business operation by allowing day shift lineworkers to perform planned scheduled work without interruption to the planned work schedule.

Q. Please provide more detail regarding the cyber-security initiative.

A. The modernization of utility infrastructure is enabling increased reliability, resiliency and efficiency. However, this new advanced infrastructure also brings with it increased reliance on more interconnected digital networks, which in turn introduces cyber security risk. As noted in the *New Hampshire 10-Year State Energy Strategy* ("State Energy Strategy"), "[c]ybersecurity threats are constantly evolving and mitigating those threats is a continual challenge for energy infrastructure operators."[17] The State Energy Strategy identifies cyber security as a critical area that must be addressed to ensure a secure, reliable, and resilient energy system for New Hampshire customers.[18]

Cyber security is a core value at Eversource Energy and the company is committed to implementing the measures necessary to protect critical infrastructure and to maintaining an organization that is appropriately sized to manage these critical efforts. Cyber threats to critical infrastructure continue to evolve, and accordingly, Eversource Energy Service Company's IT Security organization needs to expand resources to support operational initiatives, to improve security monitoring of corporate and operational networks and support the ability to respond to cyber security events.

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[17] *New Hampshire 10-Year Energy Strategy*, New Hampshire Office of Strategic Initiatives at 13 (April 2018).

[18] *Id*.

8. Variable Compensation

Q. Have you adjusted the level of expense for variable compensation?

A. Yes. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-15 (Perm), page 1, we have adjusted the revenue requirement by ($891,037) to ensure that a representative amount of variable compensation is reflected in rates.

Q. Please explain the adjustments you have made to variable compensation.

A. The Company's variable compensation plan represents the variable portion of the wages and salaries paid to non-union employees serving PSNH. Variable compensation is paid to employees in the first quarter for performance in the prior year ending December 31st based on corporate and individual performance criteria.

As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-15 (Perm), page 2, lines 44 and 45, the Company made adjustments to create a more precise Test Year by reflecting actual employee and executive cash incentive payments for 2018 that were made in March 2019 instead of using estimated amounts. Specifically, employee incentive compensation was reduced ($1,269,521), a reduction of approximately 25 percent from Test Year levels and executive incentive compensation was reduced ($259,138), or approximately 17 percent from Test Year levels.

In addition to cash-based variable compensation, the Company provides share-based variable compensation to executives and Directors. As shown on Attachment EHC/TMD-1, Schedule EHC/TMD-15 (Perm), page 2, lines 46 and 47, the Company made adjustments to the Test Year amounts to reflect a 2019 projection of share-based variable compensation. In addition, the Company made a $9,613 adjustment to employee incentive variable compensation to reflect PSNH's allocated share of the incentive payments for the 14 post-Test Year cybersecurity FTEs discussed as part of the Payroll Expense section above.[19]

9. Enterprise IT Projects Expense

Q. What adjustments have you made for Enterprise IT Projects Expense?

A. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-16 (Perm), page 1, the post-Test Year adjustment associated with Enterprise IT projects is $691,137.

Q. Please describe the basis of the adjustment for Enterprise IT Projects Expenses.

A. PSNH is allocated a portion of the costs associated with enterprise-wide IT projects implemented by Eversource Energy Service Company. The assets making up the Enterprise IT Projects include certain common use equipment, primarily computer equipment and enterprise computer applications that are reflected in plant in service at Eversource Energy Service Company rather than at PSNH, or other Eversource Energy operating companies. The carrying costs incurred by the service company in support of these projects are billed to PSNH as components of O&M expense.

Specifically, the gross amount of Enterprise IT Projects Expense billed to PSNH during the Test Year was $4,291,690 as shown on Attachment EHC/TMD-1 (Perm), Schedule

[19] Attachment EHC/TMD-1, Schedule EHC/TMD-15 (Perm), page 2, line 57.

EHC/TMD-16 (Perm), page 2, line 21, Column (B). This total was adjusted by the Eversource Energy Service Company Test Year capitalization rate of 19.36 percent to calculate a capitalized portion of $831,049 which was subtracted from the Test Year total to arrive at the net Test Year expense amount of $3,460,641.[20] A Test Year pro forma adjustment was calculated by taking a 2019 projection of total gross Enterprise IT Expense billed to PSNH of $5,148,534 and multiplying it by the 19.36 percent capitalization rate to arrive at the net Test Year pro forma amount of $4,151,778.[21] The pro forma adjustment of $691,137 is the difference between the net Test Year total of $3,460,641 and the net Test Year pro forma of $4,151,778 as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-16 (Perm), page 1. The increase in Enterprise IT Projects Expense reflected in the revenue requirement in this proceeding is driven by increased service company capital expenditures and associated plant in service.

10. <u>Lease Expense</u>

Q. What adjustments have you made to increase Test Year lease expenses?

A. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-21 (Perm), page 1, the post-Test Year adjustment associated with lease expense is an increase of $422,456.

The primary reason for the post-Test Year adjustment is the $394,683 lease expense (net

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[20] *See* Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-16 (Perm), page 2, lines 20 through 23.

[21] *See* Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-16 (Perm), page 2, lines 20 through 23.

of revenues received from third-party tenants) billed to PSNH associated with the 247 Station Drive facility in Westwood, MA.[22] During the test year PSNH was not billed an amount associated with this facility. However, it is a service company facility which provides office space for employees that perform shared service functions, including certain functions and managerial and leadership positions supporting PSNH operations. As a result, starting in 2019, the costs of operating this Eversource Energy Service Company facility are being billed to all of the Eversource Energy operating companies and the amount of the Westwood lease expense assigned to PSNH is reflected as a post-Test Year adjustment. The remainder, or $27,773, of the total post-Test Year adjustment for lease expense of $422,456 is due to contractual increases in communications leases with outside vendors ranging from 3 percent to 5 percent. The computation of the pro forma expense levels is shown in Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-21 (Perm), page 2.

11. <u>Vehicles</u>

Q. Have you adjusted the level of expense for vehicles?

A. Yes. All of the costs associated with PSNH's transportation fleet are captured within a specific clearing account. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-24 (Perm), page 1, the post-Test Year adjustment for vehicle expense is a decrease of ($1,068,474). This decrease is primarily due to a significant reduction in

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[22] Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-21 (Perm), page 2, line 54, Column (F).

depreciation expense as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC-24 (Perm), page 2. The significant reduction to depreciation expense for vehicles is driven by the accrual rate that was developed for this proceeding and discussed in the testimony of Company Witness John J. Spanos.

12. <u>Storm Reserve Accrual</u>

Q. Have you made a post-Test Year adjustment for storm reserve accrual?

A. Yes. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-25 (Perm), page 1, the post-Test Year adjustment associated with PSNH's Storm Reserve Accrual is ($4,000,000).

Q. Please describe the basis of the adjustment for the Storm Reserve Accrual.

A. Pursuant to Order No. 25,534 (June 27, 2013), the Company's MSCR is currently funded at $12 million annually. As shown on Attachment EHC/TMD-4 (Perm), in 2017 and 2018, the region experienced severe storm activity and the Company's pre-staging and restoration costs far exceeded the annual funding level of the MSCR. Accordingly, in this proceeding, the Company is proposing a refined MSCR to better align the timing of recovery with storm restoration costs. Specifically, the Company is proposing a downward adjustment to the level of storm funding included in base rates and to create a complementary storm cost recovery mechanism outside of base rates to reconcile annual storm funding shortages or surpluses to ensure timely recovery of storm costs. The decrease of ($4,000,000) shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-25 (Perm), page 1 reflects the delta between the current annual funding level in base rates for the MSCR of $12 million and the Company's new proposed annual funding level of $8 million to be included in base rates. As shown on Attachment EHC/TMD-4 (Perm), the $8 million was calculated by taking the 5-year average (2014 through 2018) of annual storm cost excluding the exceptionally large events that occurred in November 2014 and October 2017.

The Company's storm fund proposal is described in more detail in Section VIII below.

13. <u>Rate-Case Expense</u>

Q. Was it necessary for the Company to retain outside consultants and legal services for this case?

A. Yes. The Company retained the services of three expert consulting firms and one law firm to assist with the presentation of this case. All of these services were retained through a competitive bid process. Specifically, the Company is utilizing the following service providers: (1) John J. Spanos of Gannett Fleming LLC for the depreciation study; (2) Ann E. Bulkley of Concentric Energy Advisors, Inc. for cost of capital and capital structure; (3) Amparo Nieto of Economists Incorporated for the marginal cost study and allocated cost of service study; and (4) the law firm of Keegan Werlin LLP for legal services.

Q. Please describe the process that was utilized to retain the Company's external witnesses and service providers.

A. The Company invited a set of skilled service providers to participate in each RFP and established an electronic bidding process. The Company designated an internal review committee for each RFP to evaluate submitted bids. The bid evaluation included a review of the potential service providers' qualifications and relevant experience, capabilities and personnel to support the Company's rate petition, proposed fee structure, and other factors. In some cases, the committees conducted interviews with service providers as part of the overall evaluation process. The Company's external witnesses and service providers were ultimately selected based on this evaluation process and determination of the service provider that could best provide the necessary service at a reasonable price. Where appropriate, the Company invited some of these vendors to bid on services for rate cases in multiple proceedings, and cost savings that were expected to result from having a single provider serve multiple rate cases was factored into the evaluation.

Q. Is the Company proposing to recover its rate-case expense in this proceeding?

A. Yes. PSNH is proposing to recover estimated rate-case expense totaling $1,407,500 based on a 5-year amortization period, or $281,500 per year, as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-26 (Perm). PSNH will file with the Commission every 90 days the items required Puc 1905.01(a) to keep the Commission informed about the actual rate case costs throughout this proceeding. In addition, the Company will file an updated revenue requirement to incorporate actual rate case expenses incurred during the pendency of this proceeding.

Q. How did PSNH develop the estimated rate-case expense for this proceeding?

A. PSNH developed the estimates set forth in Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-26 (Perm), page 2 based on discussions with outside service providers and an evaluation of the costs incurred in prior regulatory proceedings.

PSNH will work to control rate-case expense by closely monitoring the costs of its outside service providers. PSNH will review each invoice for accuracy and reasonableness and maintain a spreadsheet identifying when each invoice is approved for payment and charged to the appropriate account on PSNH's general ledger.

14. <u>Residual O&M Inflation Adjustment</u>

Q. Have you made a post-Test Year adjustment for Residual O&M Inflation?

A. Yes. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-27 (Perm), page 1, the post-Test Year adjustment associated with Residual O&M Inflation is $93,904.

Q. How did PSNH develop the post-Test Year adjustment for Residual O&M Inflation?

A. The calculation begins with the Test Year O&M expense of $144,859,395 as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-27 (Perm), page 2, line 19, Column (C). Next, we removed the Test Year amounts totaling $143,063,911 for all expenses that are identified separately on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 2, lines 23 through 42, to calculate a residual O&M figure of $1,795,483. Then, we applied an inflation allowance based on the projected inflation factor of 5.230 percent from the mid-point of the Test Year to the mid-point of the Rate Year. The resulting inflation allowance of $93,904 was then added to the residual O&M figure resulting in the Test Year pro forma amount of $1,889,387. The details of this calculation are shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-27 (Perm), page 2.

D. Depreciation

Q. Did the Company prepare a depreciation study for this case?

A. Yes. Company Witness John J. Spanos prepared a detailed depreciation study for this case. PSNH has incorporated the results of that study into its proposed depreciation expense. Please see Mr. Spanos' direct testimony for the detailed support of the updated depreciation rates.

Q. What level of depreciation is the Company proposing for its revenue requirement?

A. PSNH has calculated a pro forma depreciation expense of $69,179,945 as shown in Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-28 (Perm), page 1, at line 21, Column (B). This is an increase of $6,854,556 from the Test Year amount of $62,325,389.

Q. Please describe in more detail the calculation of depreciation expense.

A. We have applied the depreciation rates resulting from the depreciation study performed by Mr. Spanos as of the Test Year to account balances of depreciable plant. As described in Mr. Spanos' testimony and his accompanying exhibits, the depreciation rates represent a net increase versus current levels.

Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-28 (Perm) page 2 provides a listing of the depreciable plant balances by account as of December 31, 2018. In this Workpaper, we have applied the depreciation accrual rates presented in Schedule JJS-3 to the distribution plant in service balance for PSNH. The calculated depreciation expense is the sum of the depreciation expense for each utility plant account. This is the total of $69,179,945 shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-28 (Perm), page 2.

E. Enterprise IT Projects Depreciation

Q. What adjustments have you made for Enterprise IT Projects Depreciation?

A. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-29 (Perm), page 1, the post-Test Year adjustment associated with Enterprise IT Projects Depreciation is $1,528,812. As discussed above, the Company made a post-Test Year adjustment to Enterprise IT Project expense, which is driven by the increased capital expenditures related to plant placed in service by Eversource Energy Service Company. That expense adjustment was necessary to reflect the increase in carrying charges incurred by the service company in support of those projects, which is reflected on PSNH's books of record as an O&M expense item. Similar to the previous Enterprise IT Project Expense adjustment, the Enterprise IT Project Depreciation adjustment is also driven by the increased capital expenditures and plant in service at the service company and is necessary to reflect the increase in depreciation expense allocated to PSNH.

Q. Please describe the basis of the adjustment for Enterprise IT Projects Depreciation.

A. PSNH is allocated a portion of depreciation expense from its service company affiliate, Eversource Energy Service Company. The depreciation expense is associated with certain common use equipment, primarily computer equipment and enterprise computer applications that are reflected in plant in service at Eversource Energy Service Company rather than at PSNH, or other Eversource Energy operating companies. In addition, the depreciation expense billed from Eversource Energy Service Company is subject to a capitalization adjustment. Specifically, the gross amount of Enterprise IT Projects Depreciation billed to PSNH during the Test Year was $6,277,162 as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-29 (Perm), page 2, line 21. This total was adjusted by the Eversource Energy Service Company Test Year capitalization rate of 19.36 percent (the same Eversource Energy Service Company capitalization rate is used for the Test Year and the Rate Year) to calculate a capitalized portion of $1,215,518 which was subtracted from the Test Year total to arrive at the net Test Year depreciation expense amount of $5,061,644.[23] The Test Year pro forma was calculated by taking a 2019 projected depreciation expense amount to be allocated to PSNH of $8,172,689 multiplied by the 19.36 percent capitalization rate to arrive at the net Test Year pro forma amount of $6,590,456.[24] As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-29 (Perm), page 1, the pro forma adjustment of $1,528,812 is the difference between the net Test Year total of $5,061,644 and the net Test Year pro forma of $6,590,456.

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[23] *See* Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-29 (Perm), page 2, lines 21 through 24.

[24] *See* Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-29 (Perm), page 2, lines 21 through 24.

F. Amortization of Deferred Assets

Q. Has the Company made normalizing adjustments to the Test Year amortization expense?

A. Yes. Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-30 (Perm), page 2, line 29, Column (C) shows an increase to amortization expense of $14,746,439. This net increase is primarily driven by one item, an increase of $15,512,608 associated with the amortization of deferred storm costs.

Q. What is the current status of unrecovered major storm costs for PSNH?

A. Due primarily to significant storm activity in 2017 and 2018, as of December 31, 2018, the net deficit for the Company's storm reserve totaled approximately $68.5 million. The annual storm funding previously collected in distribution rates is $12 million annually. The funding is offset against deferred storm costs, resulting in a net funding or a net deficit position for storms.

Q. Please explain how the current annual storm funding amount was established for PSNH.

A. The Company is allowed to defer costs attributable to pre-staging and restoration efforts associated with severe weather events. Under the settlement in Docket No. DE 99-099, PSNH established the MSCR, with annual funding of $3 million, for the purpose of covering the incremental costs associated with severe weather events. Under the settlement in Docket No. DE 09-035, PSNH was authorized to increase the annual level of funding to $3.5 million. PSNH was subsequently authorized to increase the funding level to $7 million annually pursuant to Order No. 25,382 (June 27, 2012) in Docket No. DE 12-110. Order No. 25,465 (February 26, 2013) in Docket No. DE 12-320 then allowed pre-staging events that had a "high" probability of reaching "Level 3" according to the Edison Event Index ("EEI") framework to be eligible for recovery under the MSCR. Under Order No. 25,534 (June 27, 2013) in Docket No. DE 13-127, PSNH was authorized to increase the funding level to $12 million annually, where it has remained since that time.

Q. Please explain in more detail how the adjustment for the amortization of deferred storm costs was derived.

A. As noted above, as of end of the Test Year, the Company had a shortfall of approximately $68.5 million in unrecovered storm costs, primarily as a result of the severe storm activity in 2017 and 2018. To address this shortfall, the Company proposes to recover this deficit, including carrying charges at the previously approved stipulated rate of return, over a five-year period. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-30 (Perm), page 2, line 24, Column (C), the Company proposes a normalizing adjustment to the Test Year of $15,512,608 to recover the amortization of the unrecovered storm cost deficit.

Q. Please describe any other significant normalizing adjustments that were made to amortization.

A. The Company made additional normalizing adjustments to amortization, which are itemized on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-30 (Perm), page 2, as follows:

- Removal of amortization of various assets previously approved by the Commission totaling ($1,102,799). These deferred asset items are itemized on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-30 (Perm), page 2, lines 19 to 23, Column (C).
- An adjustment of $336,630 shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-30 (Perm), page 2, line 25, Column (C) to account for regulatory assessment expenses and the costs of consultants hired by the Commission and the Office of Consumer Advocate.[25] In Docket No. DE 17-160, the Company sought recovery of two classes of costs—those relating to the Commission's assessment pursuant to RSA 363-A:2, and those relating to the costs of consultants hired by the Commission Staff and the Office of Consumer Advocate. In Order No 26,091 (Dec. 27, 2017), the amounts approved were $911,624 to account for an increase in the assessment to the Company for Commission expenses and $430,359 to account for Commission and Office of Consumer Advocate consultant's costs. In Docket No. DE 17-196, the Company proposed to remove $294,090 from its rates to reflect a decline in the applicable regulatory assessment.[26] In addition, the Company noted that it had been assessed additional costs to pay for consultants hired by the Office of Consumer

[25] Pursuant to RSA 365:37 II, the Commission is permitted to assess the expenses of experts it retains to the utilities in New Hampshire, and pursuant to RSA 363:28 III, the expert expenses of the Office of Consumer Advocate may likewise be assessed to utilities.

[26] November 16, 2018 Technical Statement of Rob Allen, Joseph Purington, and Christopher J. Goulding (Nov. 16, 2018), Bates Page 13, in Docket No. DE 17-196.

Advocate.[27] The amount of those new costs, however, was lower than the costs then in the Company's rates.[28] The net of those two changes represented a decrease of \$673,260, which the Company proposed to remove from rates.[29] In Order No 26,206 (Dec. 28, 2018), the Commission approved the Company's proposal to remove \$673,260 from rates. The \$336,630 shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-30 (Perm), page 2, line 25, Column (C) is necessary to reflect this \$673,260 decrease and is proposed to be amortized over a two-year period, or \$336,630 per year.

Q. Has the Company made pro forma adjustments to the Test Year amortization expense?

A. Yes. Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-30 (Perm), page 2, line 29, Column (E) shows an increase to amortization expense of \$3,200,203. This increase is driven by two items, the amortization of Merger Costs and the amortization of Environmental Costs.

1. <u>Amortization of Merger Costs</u>

Q. What is the amortization of merger costs?

A. The pro forma amortization for merger costs is \$909,020 as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-30 (Perm), page 2, line 26, Column (E). This

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27 *Id*.

28 *Id*.

29 *Id*.

represents PSNH's share of the total merger cost to achieve amortized over a 10-year period.

Q. Please describe the merger transaction between Northeast Utilities and NSTAR.

A. On October 16, 2010, Northeast Utilities and NSTAR entered into an agreement and plan of merger (as amended on November 1, 2010). In January 2011, the Commission opened Docket No. DE 11-014 in response to the announcement of the merger between Northeast Utilities and NSTAR. On April 5, 2011, the Commission issued Order No. 25,211 concluding that it did not possess jurisdiction over the transaction. Following a process conducted in Massachusetts and Connecticut for review of the merger, Northeast Utilities and NSTAR consummated the merger on April 4, 2012. Upon completion of the merger, NSTAR and its subsidiaries, including NSTAR Gas and NSTAR Electric, became wholly-owned subsidiaries of Northeast Utilities, operating as affiliates of PSNH. As of February 2, 2015, Northeast Utilities and all of its subsidiaries, including PSNH, began doing business as Eversource Energy.

Q. Did the merger of Northeast Utilities and NSTAR produce operating efficiencies that lowered the cost of service for customers of all post-merger operating affiliates, as compared to the cost of service that would have existed in the absence of the merger?

A. Yes. The merger of Northeast Utilities and NSTAR created substantial enterprise-wide benefits for all Eversource Energy customers and specific, quantifiable benefits for PSNH customers, as we discuss below. These benefits took the form of real operating cost reductions that have lowered the cost of service in this case below what it would have been absent the merger. Below, we provide a quantification of benefits that are reflected in the cost of service presented in this case.

Q. Was it necessary for Northeast Utilities and NSTAR to incur transaction and integration-related cost to achieve those operating efficiencies?

A. Yes. To complete the merger and achieve operating cost reductions, Northeast Utilities and NSTAR incurred transaction and integration costs that have been apportioned for accounting purposes across all operating affiliates. To date, Eversource Energy has received approval to recover its transaction and integration costs across all other operating jurisdictions based upon a showing that customers benefitted from actual cost reductions that are demonstrable in real terms. Other jurisdictions have allowed this recovery because the merger could not have been achieved without incurring transaction costs and, of greater significance, the merger-related costs have been far exceeded by the actual savings achieved, thereby producing substantial net benefits for Eversource Energy customers.

Q. Is the Company requesting recovery of the PSNH portion of the merger-related costs incurred to accomplish the merger and achieve cost reductions for customers in this proceeding?

A. Yes. In this case, the Company is respectfully requesting recovery of the PSNH share of one-time costs that were necessarily incurred to complete the merger (transaction costs) and to achieve the operational savings available through merger-related integration i.e., to eliminate redundant functions and achieve economies of scale in healthcare, insurance and other functional areas. These costs were incurred in direct relation to the merger in the time period 2010 to 2015. In this period, Northeast Utilities and NSTAR incurred merger-related costs of approximately $125.9 million. PSNH's share is equal to $9,090,203, or 7.22 percent of total costs. This equates to an annual amortization amount of $909,020 over ten years. The 2010-2015 merger-related costs and the cost allocation to PSNH are shown on Attachment EHC/TMD-1 (Perm), Workpaper EHC/TMD-30 (Perm), page 3.

Q. Did PSNH customers receive benefits in the form of reductions to the cost of service that would warrant recovery of these costs through customer rates?

A. Yes. PSNH customers have received direct, tangible benefits as a result of the merger—demonstrated both on an enterprise-wide basis and a company-specific basis.

Prior to the consummation of the merger, Northeast Utilities and NSTAR developed a "Net Benefits Analysis" to quantify the expected customer benefits of the merger on an enterprise-wide basis. The Net Benefits Analysis estimated the transaction and integration-related costs necessary to complete the merger and achieve operating reductions in nine functional areas across the enterprise, for the ten years following the merger. The Net Benefits Analysis demonstrated that Northeast Utilities and NSTAR anticipated generating savings of approximately $784 million on an enterprise-wide basis as a result of the merger, with an estimated six percent of that amount representing the share associated with PSNH's distribution operations (using 2011 financial data).

The Net Benefits Analysis was developed by first analyzing the current cost structures of Northeast Utilities and NSTAR, with total actual labor costs disaggregated into nine principal functional areas for analysis. The savings quantified in the Net Benefits Analysis were estimated on the basis of potential reductions in labor and non-labor costs within corporate and administrative functional areas. For non-labor cost savings, the companies examined actual costs in 17 potential areas of savings, including 13 categories of corporate and administrative costs (e.g., insurance, facilities, benefits and fleet costs) and three categories of purchasing costs (procurement, inventory and contract services).

As the Company progressed with its integration activities after the merger, the Net Benefits Analysis was updated annually in Merger Integration Reports, which showed actual annual savings through the date of each respective report; the allocation of savings between customers and shareholders; and projected savings. The Company has prepared an updated Merger Integration Report for this case as Attachment EHC/TMD-5, which provides actual savings per year for the period 2012 to 2017 and a forecast of savings through the first quarter of 2022.

Q. What does Attachment EHC/TMD-5 show with respect to merger-related savings, costs and net benefits?

A. Attachment EHC/TMD-5 shows that Eversource substantially exceeded the initial Net Benefits Analysis estimate of $784 million. Specifically, Attachment EHC/TMD-5 Report shows that the actual cumulative net savings projection is calculated to be $1,009.7 million over the 10-year period following the merger, 2012 through 2022. The projected savings of $1,009.7 million are net of $125.9 million of merger-related costs (*see* Attachment EHC/TMD-5, page 7).

Q. What is the proportional share of the enterprise-wide merger savings attributable to PSNH?

A. The proportional share of total merger-related savings attributable to PSNH is approximately $73 million over the 10-year period 2012 through 2022. This is approximately 6 percent of the total gross savings amount of $1,135.6 million. Based on the calculated estimated savings documented in Attachment EHC/TMD-5, the share of cumulative overall, enterprise-wide savings achieved through December 31, 2018 is computed as approximately $41 million for PSNH, as shown in Attachment EHC/TMD-6.

Q: What is the calculation of PSNH's share of the enterprise-wide merger-related savings?

A: Attachment EHC/TMD-6 demonstrates that the Test Year reflects net merger-related savings of approximately **$8.7 million** annually for PSNH customers. These savings represent PSNH's portion of enterprise-wide savings achieved in calendar year 2018 ($8.7 million, or 6 percent of the 2018 total amount of $134 million, per Attachment EHC/TMD-6, line 35). Net of PSNH's share of the total merger costs amortized over 10 years, as proposed in this proceeding and described below ($0.9 million), net savings are $7.8 million (in which $8.7 million minus $0.9 million = $7.8 million). Over the 10-year post-merger period, the savings generated by the merger will far outweigh the costs incurred to complete the merger. As shown on Attachment EHC/TMD-1 (Perm), Workpaper EHC/TMD-30 (Perm), page 3, PSNH's share of the total merger-related costs from 2010 to 2015 of $125.9 million is approximately $9 million or 7.22 percent of the total costs. PSNH's share of the merger costs is proposed to be recovered over 10 years, at $909,020 per year, as shown on Attachment EHC/TMD-1 (Perm), Workpaper EHC/TMD-30 (Perm), page 3.

Q: What categories of operating savings are reflected in the $8.7 million?

A: The merger savings totaling $8.7 million in the Test Year shown on Attachment EHC/TMD-6 (Perm) fall into two categories: labor-related savings and non-labor savings. Labor savings include the impact of net employee attrition and the elimination of redundant corporate positions. Non-labor savings include savings resulting from process improvements, increased purchasing leverage, elimination of duplicative corporate and administrative costs, and other efficiencies. Specific functional areas of savings include, but are not limited to, employee benefits, contract services and material and supply procurement, consistent with the projections in the original Net Benefits Analysis.

Q: How did the Company quantify actual net merger-related savings for the post-merger enterprise?

A: To quantify the merger-related savings that are inuring to the benefit of customers for this case, the Company relied on the methodology used for the Net Benefits Analysis because this is the most reliable and reasonable method for the Company to isolate and quantify the benefits of the merger. Specifically, the Company quantified the actual savings associated with particular merger-related cost reduction initiatives made on an enterprise-wide basis for labor and non-labor cost categories, within the functional areas identified in the Net Benefits Analysis, and then determined the portion allocable to PSNH's operations.

For labor-related savings, the Company quantified the fully loaded annual savings (including benefits) associated with actual merger-related employee reductions and actual merger-related attrition activity. PSNH then calculated the portion of the overall labor-related merger savings that were attributable to PSNH.

For non-labor savings, the Company first quantified the savings on the basis of specific cost-reduction initiatives undertaken by management personnel within each functional area, with savings quantified through the comparison of current and projected costs to pre-merger cost levels, or by calculating year-over-year O&M costs. PSNH then calculated the portion of overall non-labor merger savings allocable to PSNH.

Attachment EHC/TMD-6 illustrates that these are actual savings of $8.7 million annually that are providing a direct benefit to customers in the form of an overall cost of service that is lower than it otherwise would be in the absence of the merger.

Q: How did the Company quantify the merger-related "costs to achieve"?

A: The merger-related costs to achieve are primarily comprised of transaction costs (i.e., legal, banking and other costs incurred to structure and close the transaction) and integration costs (i.e., one-time costs necessarily incurred to achieve annual O&M cost reductions to the benefit of customers). Merger-related costs do not include executive severance and retention costs because the Company has excluded them from this analysis. The merger-related costs to achieve were generally recorded at the parent company level. The benefits in excess of the merger costs to achieve are shown on Attachment EHC/TMD-6.

Q: How did the Company determine PSNH's allocation of the overall merger-related savings and costs to achieve for comparison to the pre-merger estimate?

A: PSNH's share of the net merger-related savings is quantified through allocation of the enterprise-wide savings using allocators appropriate to each cost category. Attachment EHC/TMD-6 summarizes the allocation. Other labor-related savings were allocated to PSNH based upon a labor-specific allocation factor provided by the Company's Accounting Department. Generally, the charging or allocation of benefit costs follows the allocation of payroll costs. Therefore, benefit savings were attributed to PSNH based upon the labor allocator. The labor allocator was also used to allocate Administrative and General Overhead savings and savings related to the reorganization of the Company's Information Technology function, as these savings are directly tied to employee levels. Where a specific cost allocator was available (i.e., Directors Fees and Shareholders Services), that allocator was utilized to attribute savings. For Materials and Supplies Procurement and Contract Services, a general O&M allocator was developed.

Q. Is Eversource Energy on-track to achieve the merger savings identified in the Net Benefits Analysis?

A. Yes. Eversource Energy is on-track to exceed the merger-related net savings identified in the original Net Benefits Analysis. This conclusion is demonstrated by Attachment EHC/TMD-5, which (as noted above) is an updated Net Benefits Analysis incorporating actual savings achieved through December 31, 2017. Specifically, Attachment EHC/TMD-6, line 32 shows that total 10-year net savings are estimated to be $1,009.7 million on an enterprise-wide basis, which exceeds by more than $200 million the enterprise-wide net benefits projected before the merger.

Q. Is PSNH able to demonstrate that its customers have, in fact, experienced cost reductions directly related to the merger of Northeast Utilities and NSTAR that would warrant recovery of merger-related costs?

A. Yes. As discussed above, the Company has calculated total cumulative gross merger savings through December 31, 2018 to be $41 million—with $8.7 million of savings in the Test Year alone. As a supplemental demonstration of the merger cost savings, the Company has provided Attachment EHC/TMD-7. The analysis provided in this attachment identifies the cost reductions that PSNH customers have actually, directly received, in specific cost categories referenced within the Net Benefits Analysis including labor, healthcare benefits and insurance to isolate the effect of the merger on O&M expenses occurring pre-merger (2011) and post-merger (2013). As illustrated in Attachment EHC/TMD-7, comparing 2011 and 2013 (in 2013 dollars) demonstrates operating cost reductions for PSNH customers of over $2.1M annually.

The Company conservatively estimated Labor cost savings using 15 actual merger-related position reductions in New Hampshire during 2012 and 2013. After applying capitalization to these salaries, annual savings of $0.56M were realized. In addition, healthcare benefit expenses were $1.4M lower post-merger at PSNH. Insurance was decreased by $0.1M due to eliminating one of the two Directors and Officers insurance policies once the Boards of Directors of the legacy Northeast Utilities and NSTAR companies were consolidated into one.

It should be noted that the above analysis reflects a focused quantification of savings opportunities realized through the merger. For example, the position reductions identified were New Hampshire reductions only and do not reflect the FTE reductions realized at the service company level, where staff had been performing various business functions on behalf of PSNH. As suggested by the enterprise-wide savings analysis, the actual savings are substantially higher.

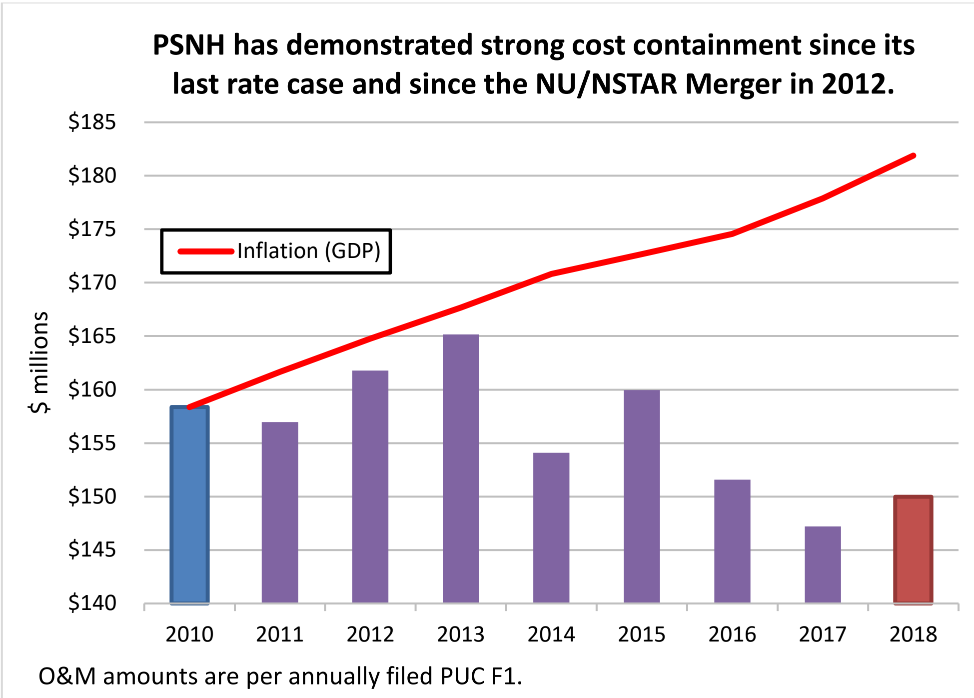
Q. Were there any additional merger-related savings for PSNH after 2013?

A. Yes. In addition to the savings discussed above, a total of 14 other redundant positions in New Hampshire were eliminated as a result of the merger, during 2014 and 2015. These positions contributed another $1.3M of labor savings. Indirectly, as corporate support positions were reduced, benefits expenses allocated to PSNH were in turn lower.

It should be noted that this quantification does not include additional savings that have been passed to customers through transmission rates each year following the merger. This level of savings exceeds the costs by any measure.

Q. How does the O&M component of the Company's revenue requirement from the 2009 Rate Case compare to the O&M component of the Company's current Application?

A. There is no practical, reliable method for the Company to track cost savings directly attributable to merger integration account by account. Since 2012, Eversource Energy has worked hard to reduce the cost of service to the customers of all of its operating affiliates through merger-related integration and through the implementation of efficiency initiatives that were unrelated to the merger. The discrete impact of the numerous merger-related and non-merger related efficiency initiatives and the multitude of transactions, costs and adjustments made to each of the numerous accounts used to track costs for routine operations generally makes it impossible to tie the impact of particular cost reduction initiatives to specific accounts. It is, however, possible to analyze the cumulative impact of the cost-reduction initiatives because the cumulative impact is reflected in the financial books of account used to calculate the revenue requirement. The substantial level of O&M savings achieved by PSNH in relation to merger-related and non-merger related efficiency gains is confirmed by comparing the NHPUC F-1 reports for 2010 and for 2018 (i.e., the Test Year in this proceeding). Specifically, the chart that follows illustrates that the Company's O&M expense was reduced by both merger and non-merger-related cost reductions since the time of the merger. This reduction in expense has occurred in spite of the fact that the Company has experienced cost pressure increases as a result of wage and salary increases and external inflationary pressures. In fact, had costs increased at pace with the rate of inflation as measured by GDP-PI over that same time period, the O&M component of the Company's cost of service would be higher by at least $32 million versus the amounts proposed in this proceeding.



It is important to recognize that PSNH, like all companies, has experienced, and will continue to experience, wage increases, and other cost increases attributable to inflation or other factors. As illustrated above, the Company has mitigated those cost pressures and produced absolute cost reductions for customers. Actual merger-related savings and savings resulting from non-merger related efficiency initiatives have occurred throughout the enterprise with the effect of reducing the costs incurred by the Company. The savings achieved by the Company are reflected in the revenue requirement in this proceeding, allowing customers to continue to benefit through lower rates as a result of the Northeast Utilities/NSTAR merger. Accordingly, the Company has included PSNH's share of the merger costs, to be recovered over ten years, in its request for rate relief.

2. Amortization of Environmental Costs

Q. What is the amortization of environmental costs?

A. As shown on Attachment EHC/TMD-1 (Perm), Workpaper EHC/TMD-30 (Perm), page 4, the Company has an Environmental Reserve Balance at the end of Test Year of $9,164,729.

Under the terms of the 1999 PSNH restructuring settlement agreement (DE 99-099), approved by the Commission,[30] and in three subsequent rate proceedings (DE 03-200, DE 06-028, and DE 09-035), PSNH was allowed to defer estimated environmental remediation costs as they are accrued for future recovery. The estimated costs were recognized when PSNH's environmental scientists quantified the costs of site remediation.

When remediation work begins at a site, the reserve account is charged for remediation costs, such as labor and materials. The regulatory asset established for environmental costs will be amortized to expense once recovery begins.

In the Company's last rate case, Docket No. DE 09-035, the projected balance in the account when the Company made its filing was $829,000. As the docket progressed, the balance was revised to approximately $8,500,000 to reflect higher projected remediation costs, primarily related to the Keene manufactured gas plant site. The original amount of $829,000 was approved via the Docket No. DE 09-035 settlement agreement, while all remaining costs were deferred, along with any future costs and adjustments, to be addressed

[30] Order No. 23,346 (Nov. 16, 1999); Order No. 23,443 (Apr. 19, 2000); Order No. 23,549 (Sept. 8, 2000).

in the Company's next rate case. The Environmental Reserve Balance of $9,164,729 includes the amount deferred from Docket No. DE 09-035 in addition to all activity that occurred within the account since that time.

As shown on Attachment EHC/TMD-1 (Perm), Workpaper EHC/TMD-30 (Perm), page 4, the Company proposes to amortize the environmental reserve balance of $9,164,729 over a four-year period or $2,291,182 per year.

G. Taxes Other than Income Taxes

Q. Please summarize your adjustments to Taxes Other Than Income Taxes?

A. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 1, line 38, Column (E), PSNH proposes to increase Taxes Other Than Income Tax by $3,120,992, which is primarily driven by an adjustment to property taxes described below.

1. <u>Property Taxes</u>

Q. Has the Company adjusted the test year expense for property taxes?

A. Yes. The Company has made a normalizing adjustment for Test Year property taxes as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 6, lines 23 and 24 by $3,058,417.

Q. How did the Company determine this normalizing adjustment?

A. The net adjustment of $3,058,417 was necessary to reflect the 2018 decision of the Supreme Court upholding the lower court's decision abating taxes on PSNH's special-purpose utility property in the Town of Bow (the "Town").[31]

At the time of the dispute, PSNH owned certain special-purpose utility property in the Town, including Merrimack Station, two combustion turbines, and a high-voltage regional electric transmission and distribution network. The dispute centered on a disagreement between the Town and PSNH regarding the proper valuation of this special-purpose utility property for tax years 2012 and 2013. The trial court found PSNH's valuation more credible and held that PSNH was entitled to a tax abatement for tax years 2012 and 2013. The Town moved for reconsideration, which was denied, and then appealed to the Supreme Court. The Supreme Court upheld the trial court's decision.

This adjustment is necessary because the tax abatement was recorded during the Test Year as a reduction to property tax expense. This abatement is a one-time, non-recurring event that reduces the Company's cost of service.

Q. Has the Company made a pro forma adjustment for property taxes?

A. Yes. The pro forma adjustment for property taxes is an increase of $281,831 as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-31 (Perm), page 1, line 23. The basis for this adjustment utilizes the latest property tax bills received from the cities and towns in PSNH's service territory. Depending on the particular municipality, these bills often need to be apportioned between distribution and transmission as reflected in

[31] *Pub. Serv. Co. of New Hampshire v. Town of Bow*, 170 N.H. 539 (2018).

Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-31 (Perm), Workpapers 1 through 4. The distribution portion of every bill is calculated and the total distribution property taxes of $47,399,352,[32] when compared to the adjusted Test Year distribution amount of $47,117,521, results in the pro forma adjustment of $281,831.[33] The Company expects to receive more current property tax bills during the pendency of this proceeding and accordingly will file an updated revenue requirement to incorporate these known and measurable changes.

2. Payroll Taxes and Other Taxes

Q. Please describe the normalizing adjustment for payroll and other taxes.

A. The normalizing adjustment for payroll taxes is an increase of $62,575 as shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-5 (Perm), page 6, line 22 to account for changes in New Hampshire unemployment and consumption taxes.

Q. Please describe the pro forma adjustment for payroll and other taxes.

A. The pro forma adjustment for payroll taxes is an increase of $392,679 as shown on Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-32 (Perm), page 1, line 23. As shown on Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-32 (Perm), page 2, the first part of this adjustment—shown in Column (G)—calculates the change in Federal Insurance Contributions Act ("FICA") and Medicare payroll tax expense based on known

32 Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-31 (Perm), page 2, line 22, Column (F).

33 The Company has capitalized $1,661,687 of property taxes allocated to distribution thereby reducing the property tax expense being sought for recovery in this proceeding.

and measurable increases to union and non-union payroll. The second part of the adjustment—shown in Column (H)—calculates the FICA, Medicare, federal unemployment, and state unemployment payroll tax expense related to the Company's proposed incremental FTEs.

H. Federal and State Income Taxes

Q. Did the Company make any Test Year adjustments to Current Income Tax Expense?

A. Yes. As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-33 (Perm), page 2, the Company made a downward adjustment to Current Income Tax of $4,750,907.

Q. What is the basis for the $4,750,907 decrease to Current Income Tax Expense?

A. The decrease to Current Income Tax expense reflects the impact of the various Test Year pro forma adjustments as well as the reduction in the New Hampshire Business Profits Tax ("BPT") rate. The BPT decreased to 7.9 percent from 8.2 percent after December 31, 2018.

Q. Please explain the 2017 Tax Cuts and Jobs Act.

A. On December 22, 2017, the TCJA was signed into law.[34] Among other things, the TCJA reduced the federal corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018.[35] This change in the tax law has a direct impact on the taxes that the Company will pay to the Federal Government as well as the deferred taxes that the

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[34] Pub. L. No. 115-97, 131 Stat. 2054: An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018.

[35] Prior to January 1, 2018, federal corporate income tax was imposed at graduated rates. As of January 1, 2018, the corporate income tax rate is a flat rate.

Company has accrued. Specifically, the tax rate reduction affects three distinct tax issues: (1) current taxes and deferred taxes; (2) property and non-property related Accumulated Deferred Income Taxes ("ADIT"); and (3) the impact of the rate reduction on the balance of ADIT reflected on the Company's books.

Q. How has the federal tax decrease related to the TCJA been reflected in this filing? [36]

A. The change in the federal income tax rate has been reflected in the permanent rate filing in two ways. First, going-forward base distribution rates will incorporate the lower tax rate. Secondly, consistent with the Commission's order in Docket No. DE 18-049, the Company is required to propose in its comprehensive rate application a recommendation for how the refund of EDIT will be addressed. The Company is proposing to use EDIT as an offset to the costs associated with the GTEP program as discussed in Sections VII and VIII below.

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[36] As described in our joint testimony filed on April 26, 2019 in support of the Company's request for temporary rate relief, the Company's temporary rate proposal includes a one-time reduction in revenue requirement reflecting the benefit of the tax savings accrued as a result of the change in the tax gross-up under the TCJA from the period January 1, 2018 through June 30, 2019. This one-time adjustment will be credited in customer rates over one year (July 2019 through June 2020). As noted above, going forward, once new base distribution rates are established as part of this proceeding, the prospective rates will be set at the currently effective tax rate, such that new rates will fully reflect the benefit of the TCJA going forward.

IV. RATE BASE COMPUTATION AND RATE OF RETURN

Q. Please describe how you determined the Company's rate of return for ratemaking purposes.

A. Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-40 (Perm), page 1 presents the five-quarter average capital structure and the cost of common equity, long-term debt, and short-term debt. Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-40 (Perm), page 2 presents the detail of the Company's Test Year outstanding long-term debt balances and associated costs.

As shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-40 (Perm), page 1, PSNH's five-quarter average capital structure as of December 31, 2018 is comprised of 39.16 percent long term debt, 6.51 percent short term debt, and 54.33 percent common equity.

Q. Did you make any post Test Year adjustments to the Company's rate of return for ratemaking purposes?

A. Yes. As reflected on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-40 (Perm), page 1, lines 33 through 41, the Company utilized a projected five-quarter average capital structure as of December 31, 2019, comprised of 41.98 percent long term debt, 3.17 percent short term debt, and 54.85 percent common equity.

The Company has employed a five-quarter average capital structure for the period ending December 31, 2019, in part, to reflect a refinancing transaction to issue up to $300 million aggregate principal amount of long-term debt securities through December 31, 2019. The

Company petitioned the Commission for approval of this financing in Docket No. DE 19-045. As explained in that filing, approximately $196.6 million of the $300 million amount constitutes the refinancing of existing debt while the remainder of approximately $100 million constitutes new debt. The Commission approved the Company's financing petition on April 26, 2019 in Order No. 26,240. The Company also has employed a five-year average ending December 31, 2019 because the corresponding time period better reflects the Company's cost of capital in a post-generation divestiture environment.

Q. Have you prepared a summary of the Company's rate-base computation?

A. Yes. Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-36 (Perm), page 1 presents a summary of the rate-base computation. As shown therein, the distribution rate base balance is $1,215,667,897.

Q. How has the Company calculated rate base for the revenue requirement?

A. The calculations supporting rate based are provided in Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-36 (Perm), page 1. This Schedule identifies the December 31, 2018 balances for Utility Plant in Service, Reserve for Depreciation, Reserve for Deferred Income Taxes (ADIT), Customer Deposits, Customer Advances, Materials & Supplies, and the cash working capital allowances. The Schedule reflects a pro forma adjustment increasing the reserve for deferred income taxes. This adjustment is necessary to remove a deferred tax asset unrelated to the distribution business that was improperly reflected in the overall tax liability balance as of the end of the Test Year. This Schedule also reflects the changes to cash working capital based on the Company's Lead Lag study, presented herein, to develop the pro forma Rate Base amount of $1,215,667,897 shown on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-36 (Perm), page 1, line 44.

Q. Have the amounts in rate base have changed significantly since the Company's last rate case?

A. Yes. The Company's last rate case (DE 09-035) was filed a decade ago using a 2008 test year. Since that time, the Company made significant capital investments to construct, replace, and repair the distribution infrastructure needed to provide New Hampshire customers with safe and reliable electric service.

V. LEAD LAG STUDY

Q. Did the Company prepare a Lead Lag Study for this case?

A. Yes, the Company prepared a Lead Lag Study to update and establish the net lag days to be used for cash working capital that it is proposing to include in base rates.

Q. What is cash working capital?

A. Cash working capital is the amount of capital that is needed by the Company to fund operations in the period between when expenditures are incurred to provide service to customers and when payment is received from customers for that service.

Q. How is cash working capital estimated through a Lead Lag study?

A. A Lead Lag study identifies the amount of time it typically takes for the Company to collect revenue from customers, as well as the amount of time the Company takes to make payment for applicable operating costs. The difference between those two numbers is used as the basis to estimate cash working capital requirements.

Q. Please define the terms "revenue lag days" and "expense lead days."

A. Revenue lag is the time, measured in days, between delivery of a service to PSNH customers and the receipt by the Company of the payment for such service. Similarly, expense lead is the time, again measured in days, between the performance of a service on behalf of the Company by a vendor or employee and payment for such service by the Company. Since base rates are based on revenue and expenses booked on an accrual basis, the revenue lag results in a need for capital while the expense lead offsets this need to the extent the Company is typically not required to reimburse its vendors until after a service is provided.

Q. Please describe the Lead Lag Study and its findings.

A. The Lead Lag Study consists of 12 schedules of calculations to separately calculate lag days for O&M expense. The Lead Lag Study produced an O&M net lag of 21.88 days or 5.99 percent (21.88/365).

A. Revenue Lag Days

Q. How is the retail revenue lag computed?

A. The retail revenue lag consists of a "meter reading or service lag," "collection lag," and a "billing lag." As shown on Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-2

(Perm), the sum of the days associated with these three lag components is the total retail revenue lag experienced by PSNH.

Q. How was the "meter reading or service lag" calculated and what was the result?

A. The service lag is 15.2 days. This lag was obtained by dividing the number of billing days in the test year by 12 months and then dividing it in half to arrive at the average midpoint of the monthly service periods.

Q. How was the “collection lag” calculated and what was the result?

A. The collection lag totaled 29.6 days. This lag reflects the time delay between the mailing of customer bills and the receipt of the billed revenues from customers. The 29.6 days lag was arrived at by a thorough examination of accounts receivable balances using the accounts receivable turnover method. End of month balances were utilized as the measure of customer accounts receivable. Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-3 (Perm), details monthly balances for the majority of the accounts receivable accounts (Customer Accounts). The yearly annual customer revenue is also shown as the sum of revenue from residential, commercial, industrial, and public street & highway lighting accounts. Total revenues are then divided by 365 to calculate the average daily revenue amount. The resulting collection lag is derived by dividing the average daily accounts receivable balance by the average daily revenue amount to arrive at the collection lag of 29.6 days.

Q. How did you arrive at the 1.00 day "billing lag"?

A. Nearly all of the Company's customers are billed the evening after the meters are read. Therefore, we have included a one (1) day billing lag. We have not made an exception for large customers, which may require additional time to process.

Q. Is the total retail revenue lag computed from these separate lag calculations?

A. Yes. As shown on Attachment EHC/TMD-2 (Perm) Schedule EHC/TMD-2, the total retail revenue lag of 45.8 days is computed by adding the number of days associated with each of the three retail revenue lag components. This total number of lag days represents the amount of time between the recorded delivery of service to retail customers and the receipt of the related revenues from retail customers.

B. O&M Cash Working Capital and Taxes

Q. Please explain O&M cash working capital.

A. The O&M cash working capital component is associated with O&M cash expenses included in the cost of service. These are expenses that the Company incurs to underwrite the activities conducted in service to customers before it receives payment from customers for those services.

Q. In determining the expense lead period, how were the weighted lead days in payment of O&M costs determined?

A. First, total O&M expense was disaggregated among payroll, payroll incentive, employee benefits, regulatory assessments, insurance expense, and other O&M expense. Payments were reviewed and the lead days were calculated for each category. Once the lead days for each category were determined, the lead days were summarized and dollar weighted according to 2018 actual annual amounts to arrive at the total O&M cash working capital requirement. The details of this calculation are shown on Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-1 (Perm).

Q. How were lead days calculated for each category of O&M and what were the results?

A. The payroll lead is shown in Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-4 (Perm). Gross payroll data is obtained from the Company's payroll system and is the basis of the payroll lead calculation. PSNH employees are paid every other Thursday for the previous two weeks' work (based on a work week of Sunday-Saturday). This results in a weighted lead of 11.97 days. Payroll incentives are paid out in March and are associated with employee service in the prior calendar year, resulting in an overall weighted lead of 270 days. Gross data for employee benefits is also obtained through the payroll system and are paid out on the same schedule as payroll. This results in a weighted lead of 11.96 days as shown in Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-5 (Perm).

Regulatory assessments are based on the fiscal year beginning in July and ending in August of the following year. Payments of regulatory assessment are typically made on a quarterly basis. This results in a weighted lead of 12.10 days as shown in Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-6 (Perm).

Insurance premiums typically run for a year and are paid at the beginning of the service period. This results in a weighted lead of (158.71) days as shown in Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-7 (Perm).

Q. How was the lead related to other O&M expenses calculated and what was the result?

A. The Company obtained a complete list of vendor payments made during calendar year 2018 directly from Eversource Energy Service Company's Accounts Payable system. The Company used a stratified-sampling method to determine a sample of 128 invoices that would best represent the entirety of other O&M expenses. The strata for the sample included five categories, which are categorized as the top twenty-five invoices, invoices greater than \$50,000, invoices greater than \$10,000, invoices greater than \$1,000, and invoices greater than \$500. Invoices in each stratum were sampled at an interval that ultimately contributed to the total sample size. Every invoice in the top twenty-five was sampled, every 5th invoice greater than \$50,000, every 20th invoice greater than \$10,000, every 150th invoice greater than \$1,000, and every 1,000th invoice greater than \$500. Once the final sample of invoices was established they were reviewed to determine the length of the service period and the date payment was made. The calculation resulted in an average lead of 45.95 days as shown in Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-8 (Perm).

Q. How were the lead days associated with taxes calculated and what was the result?

A. The property tax lead days were calculated as (25.41) based on a query of tax payments made by the Company to New Hampshire municipalities in 2018. The lead days for property taxes are presented in Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-9 (Perm). The payroll tax lead of 11.98 days was calculated based on the 2018 payments made for New Hampshire State Unemployment, Federal Employment, Medicare, and Federal Insurance Contributions Act (FICA) tax. The leads for payroll taxes are presented in Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-10 (Perm).

Federal Income Tax and State Income Tax expenses are paid on a quarterly basis. The Company compared the period between the midpoint of each month in the quarter and the quarterly payment date under the assumption that the payment is accrued evenly throughout the quarter. The result is a lead of 30.01 days for Federal Income Tax and 31.99 days for State Income Tax. Attachment EHC/TMD-2 (Perm), Schedule EHC/TMD-11 (Perm) and Schedule EHC/TMD-12 (Perm).

C. Conclusion

Q. Would you summarize the Company's proposal regarding Cash Working Capital?

A. Yes. Based on the results of the Lead Lag analysis of cash working capital, the Company identified an O&M working capital component of 21.88 days, or 5.99 percent. As detailed on Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-41 (Perm), application of these values results in a request of $13,760,897 for Cash Working Capital.

VI. STEP ADJUSTMENTS

Q. Is the Company proposing Step Adjustments as part of this filing?

A. Yes. The Company is requesting that the Commission approve Step Adjustments to recover the revenue requirements associated with incremental capital spending and discrete O&M expenses after the Test Year in Investment Years 2019, 2020, 2021, and 2022. As summarized in the table below, the illustrative estimate of the Step Adjustments is as follows:

Total Estimated Revenue Requirement Investment Years 2019 - 2022			
Investment Year 1 (2019)	Investment Year 2 (2020)	Investment Year 3 (2021)	Investment Year 4 (2022)
$15 million	$21 million	$14 million	$16 million

Q. What is the purpose of the proposed Step Adjustments?

A. One of the primary drivers for the Company's request for rate relief in this proceeding is the amount of capital investment made in the decade following the 2009 Rate Case and the financial pressure that is created where the Company has to carry the costs of that investment without rate recovery.[37] Where circumstances exist such that the relative

[37] "[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." *New England Tel. & Tel. Co. v. State*, 113 N.H. 92, 97 (1973).

growth in plant investment outpaces revenues generated by rates, there is pressure to file a distribution rate case to rebalance the revenue equation. These circumstances are clearly demonstrated by the fact that, despite all of the Company's success in containing operating costs since 2009, the Company's return on equity for the Test Year is 7.72 percent, which is well below industry standards for a fair and reasonable return, and 195 basis points lower than the return on equity of 9.67 percent authorized by the Commission in the 2009 Rate Case. The difference between the authorized level of return and actual level of return is the impact of capital investment.

The step adjustment approach is a reasonable method to allow for more timely recovery of assets placed in service after the test year without the need for multiple rate case proceedings, which is administratively inefficient and expensive for customers. Accordingly, the Company is seeking Step Adjustments to provide the Company with a reasonable opportunity to earn its allowed rate of return on significant investments that are necessary to continue to safely and reliably serve customers and prevent erosion of earnings (i.e., attrition) after permanent rates go into effect.

Q. Is there Commission precedent for the Step Adjustment approach to address earnings attrition?

A. Yes, the Commission has long employed step adjustments as a means of ensuring that a regulated utility retains its ability to earn a reasonable rate of return after implementing large capital projects that increase the utility's rate base after a test year.[38] Indeed, in the Company's 2009 Rate Case, the Commission approved a series of step adjustments and found the proposed review process was "a reasonable method to allow for a more timely recovery of assets in service without resort to a full rate proceeding."[39]

Q. What are the components of the Step Adjustment revenue requirement calculation?

A. The revenue requirement for Step Adjustments consists of: depreciation expense; property taxes; and a return on rate base. In addition, the Company has included PSNH's estimated allocated share of Enterprise IT Projects and anticipated union wage increases.

Q. Please explain the Step Adjustment revenue requirement calculation.

A. Attachment EHC/TMD-3 (Perm), page 1 presents the estimated revenue requirements calculation for the Step Adjustments with the total revenue requirement shown on Line 13.

Lines 1 and 2 reflect total distribution plant, based on PSNH's forecasted increases to plant, and total distribution depreciation reserve.

Line 3 is net utility plant calculated as the difference between Lines 1 and 2 and Line 5

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[38] *See*, *e.g.*, *Liberty Utilities (EnergyNorth Natural Gas) Corp*., DG 17-048, Order No. 26,122, at 51, 55 (April 27, 2018); *Unitil Energy Systems, Inc.*, DE 16-384, Order No. 26,007, at 10, 18 (April 20, 2017); *Unitil Energy Systems, Inc.*, DE 10-055, Order No. 25,214, at 26-27 (April 26, 2011); *Public Service Company of New Hampshire*, DE 09-035, Order No. 25,123, at 31-32 (June 28, 2010); *Eastman Sewer Company*, Inc., Order No. 24,989 (July 24, 2009) at 7-8; *Forest Edge Water Co.*, Order No. 25,017 (Sept. 23, 2009) at 8.

[39] *Public Service Company of New Hampshire*, DE 09-035, Order No. 25,123 (June 28, 2010) at 32.

shows the year-over-year change in net plant over the Investment Years.

Next, on Line 6 and Line 7, we apply the rate of return and a gross-up factor for taxes to the change in net plant amounts on Line 5 to arrive at the total return factor presented on Line 8. The rate of return is based on the Company's proposed 7.62 percent weighted average cost of capital, which is detailed on Attachment EHC/TMD-3 (Perm), page 3.[40] The gross-up factor for taxes is 1.37142 as shown on Attachment EHC/TMD-3 (Perm), page 4. The gross revenue conversion factor is calculated using applicable state and federal income tax rates. The reduced federal income tax rate of 21 percent and the BPT rate of 7.7 percent was used in this gross revenue conversion factor.

On Line 9, we calculate depreciation on the change in net utility plant. Specifically, Line 9 multiplies the change in net plant on Line 5 by the composite depreciation rate of 3.27 percent as provided in Schedule JJS-3 to Company Witness John Spanos' testimony. For ease of reference, the details of the underlying depreciation assumption of 3.27 are provided in Attachment EHC/TMD-3 (Perm), page 5.

On Line 10, we calculate the property tax expense on net utility plant. Line 10 is calculated by multiplying the change in gross utility plant on Line 4 by the average property tax rate mill rate of 2.18 percent. The 2.18 percent rate was calculated by dividing the total property tax expense, or $47,399,352 for all cities and towns served by PSNH by the gross

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40 *See also* Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-40 (Perm), page 1 of 2.

distribution plant in service, or $2,171,045,410. The details underlying the 2.18 percent assumption for property taxes are provided on Attachment EHC/TMD-3 (Perm), page 6.[41]

Q. In addition to depreciation and property tax expense, is the Company proposing to include any other expense items in the Step Adjustment?

Yes. As shown on Line 11, the Company has included PSNH's estimated allocated share of Enterprise IT Projects planned for Investment Years 2020, 2021, and 2022. The details underlying this calculation are provided on Attachment EHC/TMD-3 (Perm), page 7. On Line 12 we have also included anticipated union wage increases for Investment Years 2020, 2021, and 2022 that are expected in the collective bargaining agreement with IBEW Local 1837. The details underlying this calculation are provided on Attachment EHC/TMD-3 (Perm), page 8.

Q. Please provide more detail concerning Enterprise IT Projects.

A. From time to time, Eversource Energy Service Company implements significant enterprise-wide IT projects. The assets implemented through these Enterprise IT Projects include certain common use equipment, primarily computer equipment and enterprise computer applications, that are reflected in plant in service at Eversource Energy Service Company rather than at PSNH, or other Eversource Energy operating companies. The costs of these projects are billed to PSNH as components of O&M expense.

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41 *See also* Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-31 (Perm); Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-36 (Perm).

Enterprise IT Projects is comprised of both Enterprise IT Projects Expense and Enterprise IT Projects Depreciation. The proposed Step Adjustment will reflect the net change of both components on a year-to-year basis (similar to the calculation of PSNH net plant additions reflected above). The calculation of Enterprise IT Projects Expense on an annual basis will start with gross expense billed to PSNH and remove the capitalized portion to arrive at the amount charged to expense. The calculation of Enterprise IT Projects Depreciation on an annual basis will start with gross depreciation billed to PSNH and remove the capitalized portion to arrive at the amount charged to depreciation. In support of the calculation, a listing of Eversource Energy Service Company plant assets will be provided on an annual basis as part of the Company's compliance filing, allowing for a straightforward review of the calculation and the net change from year-to-year.

Q. Please provide more detail concerning Union Wage Increases.

A. The collective bargaining agreement with IBEW Local 1837 is set to expire in May 2020. As illustrated in Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-14 (Perm), page 2, the revenue requirement does not contain an increase for union wage increases beyond June 2, 2019. Once a new union collective bargaining agreement is in place, union wage increases will represent known and measurable expenses. Therefore, the Company proposes to reflect these expenses as a component of future annual Step Adjustments.

Q. Why hasn't the Company included estimates of Enterprise IT Project costs or Union Contractual Adjustments in the illustrative Step Adjustment #1 shown on Attachment EHC-TMD-3?

A. As described previously, the Company has included post-Test Year adjustments for each of these items within its permanent base distribution cost of service proposed in this proceeding. Therefore, the Company will not include these expense items in the first Step Adjustment since they will already be reflected in the permanent rates that will take effect July 1, 2020.

Q. What is the timing and mechanics of the proposed Step Adjustments?

A. As noted above, the Company is proposing Step Adjustments to account for capital investments and expenses in 2019 (Investment Year 1), 2020 (Investment Year 2), 2021 (Investment Year 3), and 2022 (Investment Year 4). The Step Adjustments for each of the Investment Years would take place on July 1 of 2020 (Step Year 1), 2021 (Step Year 2), 2022 (Step Year 3), and 2023 (Step Year 4). The Company will make annual compliance filings with the Commission on or before April 30 to document the prior year's actual plant additions and incremental expenses to be incorporated into the upcoming Step Adjustments. For example, the Company would file documentation supporting the actual plant additions and corresponding revenue requirement associated with Investment Year 2019 investments by May 1, 2020 with rates going into effect July 1, 2020, coinciding with the permanent rates going into effect in this proceeding.

Q. What documentation will the Company provide in its annual compliance filings?

A. The Company will file documentation with the Commission as part of the annual compliance filings demonstrating actual costs and that all plant additions for the prior Investment Year are in service.

VII. EXCESS ACCUMULATED DEFERRED INCOME TAXES

A. TCJA

Q. How has the federal tax decrease resulting from the TCJA been reflected in the filing?

A. As noted above, the reduction in the tax rate from 35 percent to 21 percent affects certain tax-related issues. Those issues are: (1) current taxes (Attachment EHC/TMD-1, Schedule 33) and deferred taxes (Attachment EHC/TMD-1, Schedule 34); (2) property and non-property related ADIT shown in Attachment EHC/TMD-8 (Perm), Schedule EHC/TMD-1 for ADIT activity in the rate period; and (3) the impact of the tax rate reduction on the balance of ADIT reflected on the Company's books as of December 31, 2017. The reduction in the federal income tax rate effective January 1, 2018 created an EDIT, which, as described in more detail below, resulted in a reduction in the recorded balance of ADIT offset by a simultaneous establishment of a regulatory liability in the same amount.

B. Deferred Income Taxes

Q. What are ADIT and EDIT?

A. ADIT represents the timing differences between expenses recorded for book purposes versus those for tax purposes. In effect, ADIT generally represents an obligation on the

Company's books to repay the federal government. In addition, ADIT is a component of rate base, whereby it typically reduces the rate base amount relative to the timing differences. As such, ADIT acts as an offset to rate base, on which regulated companies recover their weighted average cost of capital for the use of long-term resources to fund rate base.

The EDIT created by the change in federal income tax rates requires revaluing that tax obligation to the federal government at the new federal tax rate. The EDIT represents the portion of ADIT that is no longer owed to the government by virtue of the lower tax rates effective January 1, 2018, but which is instead owed to and to be returned to customers over time, subject to certain restrictions and requirements in accordance with the TCJA and applicable tax regulations, so as not to violate the normalization rules.

Q. What impact does the federal tax rate decrease have on the deferred taxes in rate base in the current filing?

A. As described above, ADIT is typically a reduction to rate base. In order to comply with the laws and regulations described below, on December 31, 2017 a regulatory liability was set up in the Company's financial statements in the amount of the EDIT, resulting in an offset to the Company's rate base as of January 1, 2018. The regulatory liability will be returned to customers in the future over time. In this proceeding, the Company is proposing to provide PSNH customers with a credit for EDIT, where the annual amount will be amortized to tax expense.

Q. Are there restrictions imposed by the Internal Revenue Code for the amount returned to customers?

A. Yes. The Internal Revenue Service ("IRS") prohibits EDIT for depreciable plant from being used to credit customer rates more rapidly than the actual annual EDIT determined by the Average Rate Assumption Method ("ARAM"). If PSNH reduced customer rates more rapidly than the actual amount determined by the ARAM, it would be in violation of normalization rules and could potentially result in the Company being disqualified from utilizing accelerated depreciation methods and possibly be subject to penalties.

Q. What are the implications of this IRS prohibition and why are the amounts preliminary at this time?

A. The actual benefit in any given year will not be known until the year is concluded and the annual tax return is filed, which typically occurs in the third quarter of the following year. The amount will vary and will be based on a number of factors, including actual depreciation expense activity recorded in any given year. The Company has presented the most recent preliminary estimates of these amounts in Attachment EHC/TMD-8 (Perm), Schedule EHC/TMD-1 (Perm).

Q. Over what period will the Company amortize the EDIT?

A. The EDIT will be refunded to customers as the timing difference for depreciation reverses. In other words, it will reverse as book depreciation exceeds tax depreciation for the underlying assets. The Company estimates that the EDIT will reverse over a life that approximates the book remaining life of the assets, or approximately 24 years.

For the non-property-related deferred taxes that have been used to determine rates, the Company proposes an amortization period of ten years relative to timing differences associated with its Pension and Other Post-Employment Benefits costs, and a five-year period for all of its remaining EDIT differences. Both of these periods relate to the remaining underlying amortization of these differences, which is similar to how amounts would have been amortized to customers in the absence of the TCJA.

In this proceeding, the Company proposes to utilize the EDIT as an offset to the revenue requirements of the GTEP, which is described in Section VIII, Part E below.

C. New Hampshire State Income Tax Changes

Q. Please describe the impact of any changes to the New Hampshire BPT.

A. New Hampshire reduced its BPT rates for the period on or after December 31, 2018 from 8.2 percent to 7.9 percent and from 7.9 percent to 7.7 percent for the period on or after December 31, 2019. The reduction in the state tax rates will affect, among other things, the state tax calculation of the EDIT that will be refunded to customers. A calculation of this impact is shown on Attachment EHC/TMD-8 (Perm), Schedule EHC/TMD-2 (Perm). Although the state portion of deferred tax liabilities has been reflected utilizing the 8.2 percent rate, the reduction of the rate to 7.7 percent necessitates a reduction in the liability, with the reduction of the liability being ascribed to EDIT in the same manner as the federal reduction. If there is any additional reduction in BPT due to the revised rates, the reduction in this tax will also be refunded to customers.

Q. Please describe the five-year refund associated with the state EDIT.

A. The state EDIT is not governed by the same normalization rules that impact the federal EDIT. Therefore, the Company has proposed a shorter amortization period of five years to provide a refund to customers in a more timely manner. As previously stated, the state EDIT amortization table is provided as Attachment EHC/TMD-8 (Perm), Schedule EHC/TMD-2 (Perm). Finally, the Company has provided Attachment EHC/TMD-8 (Perm), Schedule EHC/TMD-3, which sums up the impacts of the state and federal EDITs.

VIII. DISTRIBUTION RATE ADJUSTMENT MECHANISM

Q. Please explain the Distribution Rate Adjustment Mechanism ("DRAM") that the Company is proposing.

A. The Company is proposing a new non-bypassable reconciling rate called the Distribution Rate Adjustment Mechanism ("DRAM"). The proposed DRAM would be an annual rate change in effect from July 1 to June 30 of each year that implements certain outcomes of this rate case, as well as various other Commission directives that may occur in between rate cases. As described further below, the Company anticipates submitting a comprehensive DRAM "umbrella" filing each May 1 for the Commission's review and approval in advance of a single July 1 rate adjustment. The Company proposes a separate Tariff Rider that will incorporate the DRAM for the purposes of adjusting customer rates. The new Tariff Rider is discussed in the testimony of Company Witness Edward A. Davis.

Q. What are the benefits of having a mechanism like the DRAM in place?

A. There are several reasons why implementing the DRAM is appropriate. One reason is that utilizing a single factor to accommodate multiple rate-making matters is an efficient approach, as it reduces the need to have multiple tariffs for different policy or business purposes and creates a streamlined, predictable approach for both Company preparation and Commission review. In addition, establishing a reconciling mechanism outside of base distribution rates will allow for greater transparency in the rate setting process for certain, discrete items that are subject to variability.

Q. Is there precedent for this kind of mechanism?

A. Yes. Unitil has a mechanism called the External Delivery Charge that provides for the recovery and/or reconciliation of cost items similar to what the Company is proposing below.

Q. What costs does the company anticipate will be included in the DRAM?

A. The DRAM is designed as a single factor that will recover or refund the costs associated with multiple programs. The Company is proposing five key programs and initiatives in this case.

- The first component is an update to the Major Storm Cost Recovery mechanism, which will reconcile annual storm costs above or below the level in base rates;
- The second component is a Vegetation Management Program, which will reconcile costs above or below the level of costs provided for in base rates. The specific activities that the Company will undertake in the Vegetation Management Program are discussed in the testimony of Company Witness Robert Allen;

- The third component is a Regulatory Reconciliation Adjustment mechanism, which will recover changes in the Commission assessment from the level in base rates, the Commission and the Office of the Consumer Advocate proceeding consultant expenses, and other Commission-approved expenses;
- The fourth component is the "New Start" Arrearage Management program, which is described more fully in the testimony of Company Witness Penelope M. Conner; and
- The fifth component is the GTEP, which will recover the revenue requirement associated with a suite of system resiliency investments and clean energy demonstration projects. The system resiliency investments include an accelerated pole replacement program, a program to accelerate the relocation and rebuilding of distribution infrastructure within rights-of-way, a program to accelerate the reconductoring of bare, uninsulated conductors, and a program to accelerate the renewal of substation oil circuit breakers. The GTEP also features two demonstration projects that are designed to deliver benefits to customers and evaluate the performance of cutting-edge clean energy technologies in the field. The first is the Westmoreland Clean Innovation Project. This demonstration project is designed to provide backup power for hundreds of rural customers and critical town facilities while avoiding construction of a new electric distribution line and helping to reduce peak energy costs and greenhouse gas emissions for all New Hampshire customers. The second project is the Oyster River Clean Innovation

Project. This project will enhance resiliency of electric service while serving as an opportunity to advance the body of knowledge for future clean energy community microgrid development in New Hampshire. The GTEP is described more fully in separate testimony in which Company Witnesses Joseph Purington and Lee Lajoie discuss the system resiliency investments in Part I, and Charlotte Ancel and Jennifer A. Schilling discuss the demonstration investments in Part II.

The Company anticipates that the DRAM would be employed to recover the costs of other Commission-approved programs and initiatives in the future. For example, the Company expects the rate recovery mechanism under the Commission Staff's proposed Integrated Distribution Plan cycle to be implemented as part of the DRAM. In addition, as described in the testimony of Company Witness Davis, the Company proposes to recover LBR associated with the installation of distributed generation as part of the DRAM.

Q. Is the DRAM significantly different than recent Commission-approved methodologies for recovery of the categories of costs identified above?

A. No. For example, when the REP costs changed from year to year, distribution rates were adjusted annually to account for these changes. Similarly, a reconciling mechanism for the costs outlined above is a transparent and straightforward way to adjust rates annually. In addition, the DRAM streamlines the process for Commission review and recovery of regulatory assessments for the expenses of the Commission and consulting costs.

A. Major Storm Cost Recovery Mechanism

Q. Please explain how the current annual storm funding amount was established for PSNH.

A. The Company is allowed to defer costs attributable to pre-staging and restoration efforts associated with severe weather events. As discussed above, under the settlement in Docket No. DE 99-099, PSNH established the MSCR, with annual funding of $3 million, for the purpose of covering the incremental costs associated with severe weather events. Next, under the settlement in Docket No. DE 09-035, PSNH was authorized to increase the annual level of funding to $3.5 million. PSNH was subsequently authorized to increase the annual funding level to $7 million pursuant to Order No. 25,382 (June 27, 2012) in Docket No. DE 12-110. Then, Order No. 25,465 (February 26, 2013) in Docket No. DE 12-320 allowed pre-staging events that had a "high" probability of reaching "Level 3" according to the Edison Event Index ("EEI") framework to be eligible for recovery under the MSCR. Under Order No. 25,534 (June 27, 2013) in Docket No. DE 13-127, PSNH was authorized to increase the funding level to $12 million annually, where it has remained since that time.

Q. Please explain why the Company is proposing a new major storm cost reconciliation factor outside of base rates.

A. As recent history indicates, the frequency and severity of storm events has increased and the costs of responding to those events to restore power for customers in an expeditious fashion have increased as well. Also, recent history suggests that the current ratemaking mechanism for storm cost recovery is less than ideal for the Company and its customers.

As discussed above, due primarily to significant storm activity in 2017 and 2018, as of December 31, 2018, the net deficit for the Company's storm reserve totaled approximately $68.5 million. It is not beneficial to the Company or customers to continue forward with a ratemaking mechanism that produces deferrals of this magnitude. This lengthy delay in recovery has the equivalent financial effect of a "revenue lag" in that the Company is financing a significant investment over an extended period of time until the amounts are included in rates and recovered in revenues.

Simply put, the current MSCR mechanism is not designed to recover the costs of storm events that are exceptional in magnitude or frequency. Accordingly, the Company proposes refinements to storm cost recovery that better reflects the frequency and severity of storm events and is more beneficial for the Company and its customers.

Q. Please explain how the major storm cost recovery reconciliation mechanism included for recovery in the DRAM will work.

A. As noted above, the Company currently collects $12 million of funding for its MSCR through base distribution rates. In this proceeding, the Company is proposing to split the MSCR into two components. As for the first component, the Company proposes to continue the current practice of having a base level of storm funding in base distribution rates. In the second component, the Company proposes that a mechanism be established outside of base rates to reconcile annual storm funding shortages or surpluses to ensure timely recovery of storm costs, which will minimize carrying charges for customers. The storm cost reconciliation factor will be adjusted annually on July 1 and will reconcile the prior calendar year's storm costs compared to the base level storm funding.

Q. What level of storm funding is the Company proposing to be included in base distribution rates?

A. The Company is proposing that the annual level of storm funding to be included in base distribution rates be reduced from the current annual funding amount of $12 million to $8 million.

Q. How was the proposed annual storm funding level of $8 million established?

A. As shown on Attachment EHC-TMD-4 (Perm), the $8 million storm funding level was calculated by taking the 5-year average (2014 through 2018) of annual storm cost excluding the exceptionally large events that occurred in November 2014 and October 2017.

Q. Why have the two exceptionally large storm events been excluded from the calculation of annual average storm funding level included in base distribution rates?

A. Since exceptionally large events or an unusually high frequency of events in the aggregate occur on an irregular basis, the Company is proposing to recover these costs in a separate recovery mechanism outside of base rates. To avoid significant bill impacts by seeking recovery of exceptionally large storm costs in a single year, the Company is proposing the following recovery guidelines, with carrying charges, at the approved rate of return dependent upon the magnitude of the storm restoration:

- A one-year recovery period for storm-related costs (incremental to the $8 million in base rates) in a single-year that total less than $15 million;

- A three-year recovery period for incremental storm-related costs (incremental to the $8 million in base rates) in a single-year that totals over $15 million but less than $25 million; and
- A five-year recovery period for storm-related costs (incremental to the $8 million in base rates) in a single-year that totals over $25 million.

This proposal strikes an appropriate balance between providing the Company with a reasonable timeframe to collect the deferred storm cost balance and levelizing bill impacts to customers.

Q. Please define the requirements for a weather event to be applicable for recovery within the new major storm cost reconciliation mechanism.

A. The Company proposes to keep the requirements identical to those in place today. For all impending storms, Eversource receives an Energy Event Index ("EEI") from its outside vendor, DTN (formerly Telvent DTN). The EEI provides highly detailed weather forecasts by region and zone for the Eversource Energy service area. DTN's EEI forecast includes all relevant weather metrics needed to determine the likely severity and location of an impending storm. The EEI ranks the strength of the storm on a scale from 1 to 5, with 5 being the most severe with the potential to cause the most damage, and then applies a likelihood against the forecasted strength of the storm. Pursuant to the criteria established in Docket No. DE 12-320, pre-staging costs can be recovered through the MSCR if the weather event has a "high" (greater than 60 percent based on the forecast) probability of reaching "Level 3" or stronger, according to the EEI.[42] For non-prestaging events, once a storm has hit, for a weather event to be considered a Major Storm eligible for recovery through the MSCR certain criteria must be met. A Major Storm is defined as an event that results in either: (a) 10 percent or more of Eversource's retail customers being without power in conjunction with more than 200 reported troubles; or (b) more than 300 reported troubles during the event.[43]

Q. Please explain the annual process that the Company will follow to address the change in the major storm cost recovery mechanism component.

A. As part of its proposed annual May 1 compliance filing to the Commission, the Company will submit information and documentation, consistent with current practices, for the costs associated with the prior calendar year's storm activity or any prior year for which appropriate documentation has become available and compare those costs to the funding amount collected in base distribution rates.[44] The difference between these two amounts will be included for recovery or refund as part of the storm cost reconciliation component to be included in the DRAM effective July 1 each year.

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[42] *See* Order No. 25,465 (February 26, 2013) in Docket No. DE 12-320, at 4.

[43] *See* Order No. 25,465, at 1.

[44] The Company utilizes the services of third-party contractors to assist with storm restoration activities. The invoices from third-party contractors are not always submitted in an expeditious fashion and therefore there may be instances where the Company receives invoices for services performed in connection with storm restoration activities after the May 1 compliance filing date has passed. In such cases, the Company would seek recovery and submit the relevant documentation once it has become available in the compliance filing immediately following the receipt of the appropriate, relevant storm cost documentation.

Q. What is the benefit to customers of providing for storm-cost recovery through a separate reconciling factor?

A. As discussed above, recent history indicates that the frequency and severity of major storm events has increased and the costs of responding to those events to restore power for customers in an expeditious fashion have increased as well. These storm restoration costs can be significant and unpredictable and therefore they do not ideally lend themselves to recovery solely through base rates. Indeed, continuing forward without a reconciling mechanism for storm costs would likely result in more frequent rate cases, which would be more expensive to customers and administratively burdensome for both the Company and the Commission.

B. Vegetation Management Program Reconciling Mechanism

Q. Why is the Company proposing a separate tracking mechanism for its Vegetation Management Program?

A. As discussed in the testimony of Company Witness Robert D. Allen, the Company views vegetation management as a critical-path strategy to maintain system reliability and resiliency. The Company has done enhanced vegetation management through the REP that has delivered tangible benefits to customers in the form of reliability and resiliency and it is essential to sustain these activities to continue to deliver these benefits into the future.

Looking ahead, it is vital for the Company to continue its vegetation management activities for three fundamental reasons. First and foremost, in one of the most forested states in the country, most of the outages on the Company's system are caused by trees and tree limbs.

Second, although the Company has long taken proactive steps to enhance and protect its distribution system, the Company's system is unavoidably exposed to weather events, and vulnerable in the harsh conditions that occur with ice storms, heavy wet snow, and wind events that cause substantial damage to the distribution system and cause power interruptions. These types of events are becoming more frequent and more severe and the Company needs to take steps beyond historical practice to address this trend. Third, a resilient grid infrastructure is necessary as a foundation for an increasingly modernized grid. Without a resilient grid, real-time sensing and monitoring investments made as part of a grid-modernization program are rendered ineffective because the grid would lack sufficient foundation to optimize the use of the modern technology.

Q. Please explain why the Company is proposing to reconcile vegetation-management costs on an annual basis.

A. As discussed in the testimony of Company Witness Robert D. Allen, the level of non-maintenance cycle trim tends to vary from year to year, often due to factors outside of the Company's control, so it is appropriate to have a program and a separate tracking mechanism that addresses this variability to ensure appropriate and timely recovery.

Q. Please explain the mechanics of the Vegetation Management Program component included for recovery in the DRAM.

A. Similar to the other New Hampshire electric utilities, the Company is proposing a mechanism to reconcile the prior calendar year's actual Vegetation Management Program costs to the amount in base distribution rates. That reconciliation will be included as a component of the DRAM.

Q. What level of vegetation management expense is the Company proposing to be included in base distribution rates?

A. As shown on Attachment EHC/TMD-1, Schedule EHC/TMD-5, page 2, line 37, Column (F), the adjusted Test Year expense for vegetation management is $32,029,864. This amount consists of $14,016,121 in maintenance trimming and an adjustment totaling $18,013,743. As discussed above, the $18,013,743 adjustment primarily reflects a $16,800,000 increase associated with the reclassification of vegetation management costs as O&M expense consistent with annual amounts approved for the 2019 REP in Docket No. DE 18-177. The remainder of the $18,013,743 adjustment is a $1,213,743 increase associated with tree-trimming maintenance services performed by the Company for a third-party pole owner that have been billed but that remain unpaid.

Q. Please explain the proposed annual process that the Company will follow to address the change in the Vegetation Management Program component.

A. Annually on or about September 1 of each year, the Company will submit preliminary information to the Commission for review regarding the expected vegetation management activities and the targeted expenditures for the upcoming calendar year. The Company may provide for the Commission's consideration a plan with budgets that exceed the base amount provided for in base rates consistent with system or emergent conditions or other factors that warrant an increase in vegetation management activities to help ensure system reliability and maintain forward progress with the Company's long-term vegetation management plan for the system.

Consistent with the practice under REP, the Company will meet with Staff to discuss its preliminary plan and submit a revised plan incorporating Staff's feedback on or about November 15. The Company would request a decision by the Commission approving the twelve-month plan by January 1.

Then, on May 1 of the calendar year following that twelve-month period, the Company will submit a filing with the Commission presenting information for the prior calendar year's vegetation-management costs and compare it to the funding amount collected in base distribution rates. The difference (i.e., any over- or under-collection) between these two amounts would be included for recovery from customers or credited against future Vegetation Management Program expenditures above the amount set in base distribution rates, with appropriate carrying charges, as part of the Vegetation Management Program component to be included in the DRAM effective July 1 each year.

C. Regulatory Reconciliation Adjustment Mechanism

Q. What level of expense is the Company proposing to be included in base distribution rates for regulatory assessment expenses?

A. As shown on Attachment EHC/TMD-2, Schedule EHC/TMD-5, page 2, line 39, Column (H), the Company proposes to include $4,766,319 in base rates for regulatory assessment expenses.

Q. Please explain how the Regulatory Reconciliation Adjustment Mechanism included for recovery in the DRAM will work.

A. The regulatory reconciliation adjustment component will be adjusted annually and shall include the following three categories of charges (or others that might come from law, rule, or order): (1) changes in the amounts above or below the total Commission assessment allowed for recovery in base distribution and energy service rates in accordance with RSA 363-A:6; (2) prior calendar year deferred Office of Consumer Advocate and Commission proceeding expenses consistent with those previously approved in Docket No. DE 17-160 and DE 18-177; and (3) other Commission approved regulatory expenses or recoveries (e.g., costs associated with pilot programs approved in Docket No. DE 16-576).

Q. Please explain the annual process that the Company will follow to address the change in the cost included in the regulatory reconciliation adjustment component.

A. As part of its proposed annual May 1 compliance filing to the Commission, the Company will file information reconciling prior year activity and submit for recovery the prior calendar year's expenses eligible for recovery via the regulatory reconciliation adjustment component included in the DRAM effective July 1.

D. New Start Arrearage Forgiveness Program

Q. Please explain why the "New Start" Arrearage Forgiveness Program is being included for recovery in the DRAM.

A. As described in the testimony of Penelope M. Conner, the Company is proposing to implement a New Start Arrearage Forgiveness program. New Start provides payment assistance for qualifying residential customers struggling with past due utility bills. The concept of New Start is straightforward, in that for every one-time monthly payment a customer enrolled in the program makes to the Company, a portion of their past due balance will be forgiven.

Q. What costs related to the New Start program is the Company seeking for recovery?

A. The Company is seeking to recover the costs associated with the portions of past due balances forgiven described above and the program implementation costs. As discussed in the testimony of Company Witness Penelope M. Conner, the Company estimates that it will cost approximately $1.7 million to implement the New Start program, including reprogramming and testing the Company's C2 System, and its back-office processes and web interfaces (e.g., Payment Plan Portal).

Q. Please explain the Company's proposal for recovering the past due balances forgiven through the New Start Program.

A. Consistent with its approach in Massachusetts, the Company is seeking to recover 100 percent of the forgiven past due balance amounts for customers enrolled in the New Start program through the DRAM.

As part of its proposed annual May 1 compliance filing to the Commission, the Company will submit the tracked amounts of forgiven past due balances for inclusion in the next DRAM rate adjustment effective July 1.

Q. Please explain the Company's proposal for recovering the implementation costs of the New Start Program.

The Company is not seeking recovery of the capital costs associated with program implementation through the DRAM. Instead, if the New Start program is approved by the Commission, the Company would seek recovery of the capital costs associated with program implementation through the Step Adjustment mechanism.

E. Grid Transformation and Enablement Program

Q. Please provide an overview of the GTEP cost-recovery mechanism as presented in this testimony.

A. The GTEP is a multi-year initiative to accelerate capital work targeted at upgrading the condition of the distribution system for greater resiliency and the integration of advanced clean energy technologies. To accomplish the objectives of the GTEP, the Company is requesting approval of a cost-recovery mechanism to provide post-rate case support for the program costs. The Grid Transformation and Enablement Program Factor ("GTEP Factor") is an annual rate adjustment and reconciliation factor to recover: (1) actual, eligible preauthorized expenditures on a calendar year basis, starting with the Rate Year; and (2) a reconciliation component in the second year and beyond. The GTEP Factor would be part of the DRAM and will provide a rate adjustment for Commission-approved investments that are forecasted to be placed in service pursuant to GTEP, subject to future reconciliation. The mechanism is essential to enable the Company to fund the program investments described in the GTEP Part I testimony of Mr. Purington and Mr. Lajoie, as well as the demonstration projects described in the GTEP Part II testimony of Ms. Ancel and Ms. Schilling.

Q. Will the GTEP Factor be limited to preauthorized expenditures?

A. Yes. Only investments that are preauthorized by the Commission will be eligible for cost recovery through the GTEP Factor. Commission preauthorization of GTEP investments means that the Commission will approve the decision to proceed with those investments, and in future reconciliation proceedings will review the prudence of the implementation of these investments pursuant to that authorization.

Q. Are you presenting any schedules or exhibits in support of the GTEP Factor proposal?

A. Yes, in support of this proposal, we are presenting Attachment EHC/TMD-9 (Perm), which calculates an illustrative annual revenue requirement for the program. There are four schedules contained in this Attachment:

- Schedule EHC/TMD-1 (Perm) shows a summary of the revenue requirements;
- Schedule EHC/TMD-2 (Perm) shows capital additions and O&M expense associated with the program;
- Schedule EHC/TMD-3 (Perm) shows support for income tax calculations; and
- Schedule EHC/TMD-4 (Perm) shows return on rate base and capital structure.

Q. Why does GTEP require a cost-recovery mechanism for post-rate case support of program investments?

A. The GTEP investments in substations, overhead lines, poles and demonstration projects are critical investments to upgrade the condition of the distribution system for greater resiliency and for the integration of advanced clean energy technologies. The program will enable PSNH to identify, plan and develop projects to meet customer demand for increased system integration of clean energy technologies into the future. The GTEP Factor is necessary to support dedicated funding for the planned levels of investment, ensure prudent cost incurrence and documentation for program expenditures, and provide timely recovery with a reasonable rate path for customers.

Q. What are the incremental investment requirements for the GTEP?

A. Commencing July 1, 2020, the GTEP program investments will include $37.5 million annually for resiliency-focused investments, as described in the testimony of Mr. Purington and Mr. Lajoie. PSNH expects that spending in 2020 will be a portion of the annual estimate, whereas calendar years 2021 and beyond will reflect spending closer to the full annual estimate. In addition, investments for demonstration projects as described in the testimony of Ms. Ancel and Ms. Schilling are expected to commence in 2021. Expected capital additions for all of these investment categories are summarized in Attachment EHC/TMD-9 (Perm), Schedule EHC/TMD-2 (Perm).

Q. Will the Company implement specific accounting processes for GTEP costs?

A. Yes. Upon receipt of the Commission’s order authorizing implementation of the GTEP, the Company will implement an accounting process to specifically track associated program costs. The Company will track GTEP projects and work orders separately from base capital work. The investment categories to be created for the initial filing are anticipated to be classified as follows:

- Poles
- Overhead line relocation, reconstruction, and reconductoring
- Substation renewal
- Demonstration projects

All GTEP work orders shall link to a specific GTEP project. All GTEP projects shall link to a specific investment category. The project approval process shall remain consistent with that of normal base capital work, which involves adhering to the APS-1 Project Authorization Policy, including review of the project process and associated cost incurrence at project governance meetings.

Q. Please describe the annual process for updating the GTEP Factor.

A. This process will entail several major steps.

First, on or about September 1 of each year, the Company plans to file a preliminary forecast of GTEP investments for the following calendar year and discuss that plan with Commission Staff.

Next, on or about November 15 of each calendar year, and starting in 2020, it shall provide the Commission with a compliance filing that forecasts the Company's expected spending under the GTEP Factor for the upcoming calendar year. This compliance filing will incorporate Staff's earlier feedback on the program. The Company would request an order approving the plan by January 1.

Subsequently, on an annual basis and as part of the Company's May 1 compliance filing under the proposed DRAM, the Company will provide two GTEP-related items: (1) a revenue requirement calculation for the current calendar year consisting of actual capital spend to date and a forecast for the balance of the year, and (2) a report to the Commission reconciling actual GTEP costs in the prior period, including a proposed reconciling adjustment to be made as part of the revenue requirement for the upcoming year. The current-year GTEP revenue requirement and prior-year reconciliation amounts approved by the Commission will be implemented as part the annual July 1 DRAM rate adjustment.

Q. Please describe in further detail the type of information the Company will provide in its annual reconciliation filings.

A. As part of its May filings, the Company will calculate a reconciliation of the actual revenue requirement for the prior calendar year versus the previously-approved forecasted revenue requirement that had been incorporated into rates under the DRAM. For this reconciliation, the Company will provide exhibits with information such as the investment summary by month for the preauthorized GTEP investments that were placed in service in the investment year; a summary view of capital additions categorized by plant account and investment category; and a summarized list of all GTEP investments placed in service.

Q. When will the revenue requirements from GTEP be incorporated into base distribution rates?

A. The Company proposes to incorporate previously-authorized capital investments and recurring O&M from the GTEP Factor into base distribution rates at the time of the Company's next rate case following the current rate case proceeding, at which time the GTEP revenue requirement within the DRAM will reset to include forward-looking incremental expenditures.

Q. Will interest accrue on over- or under-recovery of the GTEP revenue requirement?

A. Yes. Interest will accrue on over- or under-recovery calculated on the average monthly balance using the prime rate.

Q. How will the annual revenue requirement be calculated?

A. For the year in which eligible GTEP investments are placed into service, the annual revenue requirement will be calculated on a monthly basis. The annual revenue requirement will be calculated based upon average annual costs in subsequent years. The return on eligible GTEP plant investment shall be the most recent weighted average cost of capital approved in the Company's most recent rate case.

Depreciation expense shall be set at the depreciation rates approved by the Commission in the Company's most recent rate case. For the year during which the eligible GTEP plant is placed into service, the Company shall calculate depreciation expense by: (1) dividing the annual depreciation rate by twelve; and (2) applying the resulting rate to the average monthly plant balance over the course of the year. Depreciation for subsequent years shall be based on the average of beginning and end of year plant balances.

Incremental property tax expenses associated with the GTEP investments will be included in the GTEP revenue requirement.

Q. Will the GTEP Factor recover O&M costs?

A. Yes. O&M costs will be defined as the actual monthly GTEP O&M expenses incurred through the prior twelve-month investment year, and proven to be incremental, preauthorized, and reasonable. The Company expects to incur incremental O&M associated with the resiliency-focused investments, as well as recurring non-labor O&M for warranty and maintenance costs for the Westmoreland Clean Innovation Project, as described in the testimony of Ms. Ancel and Ms. Schilling.

As shown on Attachment EHC/TMD-9 (Perm), Schedule EHC/TMD-2 (Perm), Line 40, an annual O&M figure for the program is estimated to be $5,890,000. This includes $5,750,000 in incremental expenses associated with the resiliency initiatives, and $140,000 of non-labor expenses on a recurring basis once the Westmoreland Clean Innovation Project has been placed in service.

Q. From a rate design perspective, how will costs be allocated to the rate classes?

A. GTEP costs shall be allocated to each rate class using the distribution revenue allocator approved in the Company's most recent base distribution rate case. In addition, the GTEP revenue requirement will be recovered from customers through a tariff update corresponding to the DRAM. Please see Attachment EAD-1 and EAD-2 to the testimony of Company witness Edward A. Davis, which includes a proposed update to the tariff entitled "NHPUC No. 10 – Electric Delivery."

Q. Similarly, how will costs be collected from customers?

A. The GTEP Factor shall collect costs as part of the DRAM based on rate design principles as described in the testimony of Company witness Mr. Edward Davis.

Q. Has the Company developed an illustrative revenue requirement for the program?

A. Yes. Attachment EHC/TMD-9 (Perm) an illustrative annual revenue requirement computation for GTEP, absent any mitigation measures. The illustrative revenue requirement is based on estimates of expenditures under each investment category and is provided primarily for the purposes of illustrating the order of magnitude of the program. A summary of the revenue requirement can be found on Attachment EHC/TMD-8 (Perm), Schedule EHC/TMD-1 (Perm). As shown on Line 41, Column (B), the revenue requirement for the Rate Year is estimated to be $4,488,697.

Q. Please summarize the Company's request with respect to the GTEP Factor.

A. The Company seeks the Commission's approval of the GTEP Factor, which will authorize PSNH to obtain preauthorization for the investments described and a budget based on the estimated project investments, including the proposed process for compliance filings, rate adjustments, and reconciliation.

In addition, the Company requests to include $4,488,697 for the revenue requirement of GTEP in the Rate Year as part of the DRAM. This amount is shown in Attachment EHC/TMD-9 (Perm), Schedule EHC/TMD-1 (Perm), Line 41, Column (B) and reflects the partial-year investments that the Company plans to make in calendar year 2020. The amount will be reflected as part of the DRAM as of July 1, 2020, subject to reconciliation as part of the proposed May 1, 2021 DRAM compliance filing.

Q. Has the Company identified an approach to mitigate the rate impact of GTEP on customers?

A. Yes. In the Commission's order in Docket No. DE 18-049 ("Investigation to Determine Rate Effects of Federal and State Corporate Tax Reduction"), the Commission instructed the Company to address the impacts of the EDIT resulting from the TCJA as follows:

> [I]f Eversource files a distribution rate case for rates effective July 1, 2019, or before, Eversource shall include a calculation of the tax reductions, a proposed refund of the over-collection from January 1, 2018, with interest, and a downward rate adjustment of some type reflecting EDIT, and a reduced revenue requirement.[45]

Pursuant to this requirement, the Company proposes to partially offset the GTEP revenue requirement with an annual credit to that revenue requirement in the amount corresponding to the EDIT amount available for refund according to normalization guidelines.

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[45] Order No. 26,177 (September 27, 2018).

Q. Please explain the rationale for the Company's proposal to leverage the EDIT to offset GTEP costs.

A. As described in the testimony of Mr. Purington and Mr. Lajoie, the incremental investments proposed under GTEP are critical to updating the system in order to provide a higher level of resiliency and to support the integration of advanced clean energy technologies. The EDIT resulting from the TCJA is a once-in-a generation funding source that provides a unique opportunity to mitigate the customer bill impacts for the transformational investments within the objectives of GTEP.

Q. What is the approximate amount of the annual credit to the GTEP revenue requirement under the Company's proposal?

A. The EDIT amount available for refund on an annual basis is described above in Section VII and is calculated as shown in the schedules of Attachment EHC/TMD-8 (Perm). In the Rate Year, this amount is approximately $7.6 million on a pre-tax basis.

Q. How will the EDIT amount be reflected in distribution rates?

A. The annual EDIT credit will be a reduction to the annual GTEP revenue requirement and will be reflected in the DRAM starting in July 1, 2020.

IX. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.