THE STATE OF NEW HAMPSHIRE
SUPREME COURT
No. ______________

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
D/B/A EVERSOURCE ENERGY

Notice of Intent to File Rate Schedules

PUC DOCKET NO. DE 19-057

APPENDIX TO
APPEAL OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
D/B/A EVERSOURCE ENERGY
PURSUANT TO RSA 541:6 AND RSA 365:21
(NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION)

Matthew J. Fossum,
N.H. Bar No. 16444
Senior Regulatory Counsel
Eversource Energy Service
Company
780 N. Commercial Street
Manchester, NH 03101

Table of Contents

780 N. Commercial Street
P.O. Box 330
Manchester, NH 03105-0330

Matthew J. Fossum
Senior Regulatory Counsel

603-634-2961
matthew.fossum@eversource.com

October 9, 2020

Debra Howland
Executive Director
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, NH 03301-2429

RE: Docket No. DE 19-057
Public Service Company of New Hampshire d/b/a Eversource Energy
Notice of Intent to File Rate Schedules

Settlement Agreement

Dear Director Howland:

Public Service Company of New Hampshire d/b/a Eversource Energy ("PSNH") is pleased to enclose for filing a comprehensive settlement agreement pertaining to PSNH's permanent rate request in the above-captioned proceeding. The enclosed settlement reflects the agreement of all parties to the case to resolve the matters pertaining to this rate filing and is to be considered by the Commission during the hearings scheduled to begin on October 26, 2020.

If you have any questions, please do not hesitate to contact me. Thank you for your assistance with this matter.

Very truly yours,

Matthew J. Fossum
Senior Regulatory Counsel

Enclosures
CC: Service List

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY

Docket No. DE 19-057

SETTLEMENT AGREEMENT ON PERMANENT DISTRIBUTION RATES

This Settlement Agreement on Permanent Distribution Rates ("Settlement Agreement") is entered into this 9th day of October, 2020, by and among Public Service Company of New Hampshire d/b/a Eversource Energy ("PSNH," the "Company," or "Eversource"), the Staff of the Public Utilities Commission ("Staff"), the Office of the Consumer Advocate ("OCA"), Clean Energy New Hampshire ("CENH"), New Hampshire Department of Environmental Services ("NHDES"), The Way Home ("TWH"), Acadia Center, Walmart, Inc., AARP New Hampshire ("AARP"), and ChargePoint, Inc. (collectively, "Settling Parties"). This Settlement Agreement resolves all issues among the Settling Parties regarding the Company's request to establish permanent rates in Docket No. DE 19-057.

SECTION 1. INTRODUCTION AND PROCEDURAL HISTORY

1.1 On March 22, 2019, PSNH filed with the New Hampshire Public Utilities Commission ("Commission") a Notice of Intent to File Rate Schedules pursuant to N.H. Code Admin. Rule Puc 1604.05 pertaining to a request for temporary rates. On April 26, 2019, the Company filed with the Commission proposed tariffs and rate schedules, testimony, attachments and other information supporting that request. In that submission, PSNH sought an increase in temporary rates of approximately $33 million effective July 1, 2019, pending the Commission's determinations on the Company's permanent rate request. On April 26, 2019, the Company also filed with the Commission a Notice of Intent to File Rate Schedules pertaining to its request for permanent rates.

1.2 On March 25, 2019, the OCA filed a letter of participation in this docket pursuant to RSA 363:28. The Commission granted motions for interventions in this docket on various dates by CENH, NHDES, TWH, Acadia Center, Walmart, Inc., AARP, and ChargePoint, Inc.

1.3 On May 8, 2019 the Commission issued Order No. 26,250, suspending PSNH's proposed tariff for a temporary rate increase pending further investigation.

1.4 On May 28, 2019, the Company submitted its permanent rate filing seeking an increase in rates of approximately $70 million effective July 1, 2019, inclusive of the temporary rate increase. The request was supported by proposed tariffs and rate schedules, testimony and attachments from 14 witnesses, and other information supporting that request. On June 7, 2019 the Commission issued Order No. 26,256 suspending Eversource's proposed tariff for a permanent rate increase pending further investigation.

1.5 Following discovery and a technical session, on June 13, 2019, PSNH filed a settlement agreement on temporary rates ("Temporary Rates Settlement Agreement") signed by PSNH, Staff, OCA and TWH.[1] On June 27, 2019, the Commission issued Order No. 26,265 approving the Temporary Rates Settlement Agreement for a temporary increase of $28.3 million in the Company's annual distribution revenues effective for service rendered on and after August 1, 2019. The temporary rates were approved subject to reconciliation based on the outcome of the permanent rate case.

1.6 On June 28, 2019, the Commission approved an initial procedural schedule for adjudication of the Company's permanent rate request that included multiple rounds of discovery, technical

[1] CENH did not object to the Temporary Rates Settlement Agreement but elected not to sign it.

sessions, settlement conferences, Staff and intervenor testimony and Company rebuttal testimony, merits hearings, and an anticipated Commission order by May 20, 2020. Staff, OCA and other intervenors filed testimony on December 20, 2019 and the Company filed its rebuttal testimony on March 3, 2020.[2]

1.7 On March 24, 2020, the Staff filed a letter in the docket describing the status of the matter and the agreement of the Company to a three-month extension of the procedural schedule to account for the state of emergency declared by Governor Sununu on March 13, 2020, regarding the COVID-19 pandemic. PSNH confirmed its agreement to the three-month extension in a letter filed on March 26, 2020. On April 24, 2020, Governor Sununu issued Exhibit D to Executive Order #29, pursuant to Executive Order 2020-04 (Executive Order #29, Ex. D), extending the Commission's authority to suspend rate schedules by six months, from 12 to 18 months.[3]

1.8 AARP filed a pleading on April 16, 2020 seeking an order directing PSNH to file supplemental testimony to reflect the impacts of the pandemic. AARP also requested that the Commission stay the effectiveness of the previously approved temporary rates. PSNH filed an objection to these requests on April 27, 2020. The Commission denied the AARP request as to the temporary rates in Order No. 26,363 (June 16, 2020). However, the Commission directed PSNH to file supplemental testimony and, invoking the authority previously granted by the Governor in his emergency directives of April 24, 2020, suspended PSNH's permanent rate schedule for an additional 6 months. This resulted in a full 18-month period of suspension, to

[2] Pursuant to the Commission's Order No. 26,363, supplemental testimony on return on equity and other topics was also filed on July 16, 2020 by the Company, Staff and OCA.

[3] *See* RSA 378:6, I(a) (ordinarily providing for 12-month suspension period).

November 28, 2020.[4] The Commission also directed Staff to work with the parties to develop and propose a procedural and hearing schedule in order to resolve this matter as expeditiously as possible.[5]

1.9 On June 19, 2020, Staff submitted a proposed procedural schedule for hearings on the merits. On July 7, 2020, the Commission issued a Secretarial Letter approving Staff's proposed procedural schedule including 20 days of hearings beginning on August 19, 2020 and ending October 30, 2020.[6]

1.10 In the weeks prior to and following the Commission's order extending the suspension period, the Company, Staff and OCA engaged in settlement discussions, which were subsequently expanded to include additional intervenors. Based upon these discussions, the Settling Parties agreed to the terms of this Settlement Agreement, subject to Commission approval. The Settling Parties recommend and request that the Commission approve this Settlement Agreement without modification.[7]

4 Order No. 26,363, at 9-10 (June 16, 2020).

5 On May 28, 2020, the Commission issued Order No. 26,361 to remove from this docket issues related to rate design for charging electric vehicles ("EV") raised by intervenors to Docket No. IR 20-004, the Commission's investigation of EV charging rates and rate structure. Issues pertaining to EV infrastructure were retained in this docket.

6 On July 17, 2020, OCA submitted a motion for rehearing of certain determinations in the July 7 secretarial letter. Specifically, after making various rules-based, statutory and constitutional arguments, OCA asked the Commission to reconsider its decision to hold remote hearings in the rate case and to convene the parties for a prehearing conference. The Commission denied these requests on August 10, 2020 via Order No. 26,392.

7 AARP filed a motion on September 25, 2020 seeking certain procedural rulings relative to how the Commission would conduct its hearing on this Settlement Agreement. That motion was withdrawn, without prejudice, on October 5, 2020.

SECTION 2. REVENUE REQUIREMENT INCREASE

2.1 The Company shall be allowed a total revenue increase of $44.987 million effective for service rendered on and after January 1, 2021, to be reconciled back to July 1, 2019, the effective date of temporary rates, consistent with Order No. 26,265 (June 27, 2019) in this proceeding.

2.2 The agreed-upon revenue increase reflects adjustments that have been made to the revenue requirement in order to reach settlement.

2.3 The Settling Parties agree to the following: (a) a total revenue requirement increase of $44.987 million which includes a reduction of $1.1 million as a settlement concession, among other adjustments up and down; and (b) that the Company shall be authorized to establish a regulatory asset in the amount of $5 million to be recovered over 10 years through an annual amortization of $500,000 per year following approval of this Settlement Agreement (i.e., over the period July 1, 2019 through June 30, 2029).

2.4 It is explicitly understood and agreed to among the Settling Parties that adjustments made to the revenue requirement for purposes of reaching settlement shall not establish precedent for future rate proceedings.

SECTION 3. PLANT IN SERVICE

3.1 Staff's testimony includes observations and concerns about the Company's documentation of certain capital projects involving their planning, budgeting and management. To address this concern, the Company shall work with Staff and the OCA to develop a regulatory review template to guide the development and production of capital project documentation generated through the Company's capital authorization process. The purpose of the regulatory review template shall be to facilitate the Commission's review of future requests of the Company to recover the costs of capital investments. To the extent possible pending completion of the business process audit described in Section 3.2 below, the Company, Staff, and the OCA intend to develop the template prior to May 2021 for incorporation in the Company's step adjustment filing due May 1, as described below in Section 10. The template shall be subject to revision in future years based on the recommendations resulting from the business process audit, described below in Section 3.2.

3.2 To further address Staff's concerns regarding the inconsistent documentation of capital projects as described in Section 3.1 above, the Company agrees to a business process audit of the Company, consistent with the one described in Appendix 2 to be conducted and overseen by Staff. The Company may provide input on the list of potential bidders and the scope of services to be provided in the business process audit RFP. Staff's selection decision of an auditor shall be final and shall not be appealable to the Commission by the signatories to the Settlement Agreement.

3.3 The OCA's testimony includes observations and concerns regarding the Company's investments in automated meter reading ("AMR") infrastructure. To address these observations and concerns, the Company shall employ a nine-year depreciable life for its existing AMR infrastructure, using whole life depreciation.

3.4 During the proceeding, the Company provided information relating to its accounting for the retirement of meters that were taken out of service as part of the Company's deployment of automated meter reading ("AMR") meters. The Settling Parties have discussed the meter retirements during discovery, technical sessions, and information exchanges to review the accuracy and validity of the accounting for and the numbers of meters reflected in the settled cost of service in this proceeding. Staff and the OCA continue to have questions regarding the accounting for and the numbers of the meter retirements. As a result, the Company, Staff, and the

OCA shall continue working collaboratively to verify the accuracy of the accounting for and number of meter retirements. To facilitate this discussion, the Company may elect, either on its own or at the request of Staff or the OCA, to hire an independent accounting firm, at the Company's cost, to verify the accuracy of the meter plant account 370, and in particular the retirement entries associated with the meters that were removed as part of the AMR deployment. The scope of this work will include an analysis of meters and transactions currently recorded on the Company's books and records. The independent accounting firm's work may include some or all of the following tasks: (1) obtain an understanding of the addition, unitization and retirement process by selecting transactions, testing these transactions for certain attributes, and identify their existence in the appropriate asset systems; (2) validate the existence of the meter assets included in rate base through a reconciliation of assets to the respective asset systems (Meter Management System and/or Customer Information System); (3) determine that the cost and unit quantity recorded for each asset included in the fixed asset system is appropriate; and (4) determine the appropriateness of "AMR meter" retirements. Nothing in this settlement precludes the Staff or the OCA from petitioning the Commission, after such collaboration, to review the accounting for the retirement of the Company's metering infrastructure , except that any such petition, if filed, must be filed no later than April 30, 2021.

SECTION 4. METERING INFRASTRUCTURE: FEASIBILITY ASSESSMENT

4.1 The OCA's testimony includes observations and concerns regarding the Company's investments in automated meter reading ("AMR") infrastructure. For example, the functionalities provided by AMR infrastructure are limited when compared to those provided by advanced metering, which may be necessary to offer advanced rate designs and other offerings due to their ability to collect and transmit interval data. In light of these observations and concerns, the

Company shall conduct an assessment of the feasibility of deploying advanced metering functionality ("AMF") in New Hampshire, building upon the work recently conducted by Eversource Energy in Connecticut and filed with the Connecticut Public Utilities Regulatory Authority. The assessment will include the following parameters, with the recognition that conditions in New Hampshire are different than those that prevail elsewhere in the Eversource Energy service territories:

(a) The assessment shall be performed by an outside consultant mutually agreed to by Staff, the OCA, and PSNH. The outside consultant responsible for the feasibility study in Connecticut shall be evaluated first and, if not mutually agreed to by Staff, the OCA, and PSNH, other consultants shall receive consideration.

(b) The assessment shall include (but not be limited to) an assumption that AMR meters had not been deployed by PSNH.

(c) The Settling Parties agree that the assessment shall include the following components:

1. The Assessment shall include a project management phase with a deliverable documenting the detailed project schedule with participation requirements by subject matter experts and stakeholders and weekly reports from the consultant documenting progress on Assessment deliverables highlighting project risks and mitigations;
2. The Assessment shall analyze multiple scenarios, including but not be limited to: (i) a scenario that assumes that previously deployed analog meters remain in service and are manually read; (ii) the Company's currently deployed meters and its current approach to meter reading; and

(iii) a scenario assuming that the Company's existing AMR meters are replaced with technologies capable of offering advanced metering functionality, considering both full and partial (opt-in) meter deployment scenarios.

3. For each scenario that involves the deployment of new technologies, the assessment shall analyze the effects of all practicable deployment timelines;
4. For each scenario, the Assessment shall quantify life cycle costs to deploy and maintain new infrastructure over the expected useful life of the assets;
5. For each scenario, the Assessment shall document life cycle costs and benefits that can be quantified on a net present value basis, as well as those that may be characterized qualitatively;
6. The Assessment shall examine whether existing broadband or cellular communication networks can be used and meters or other devices offering advanced metering functionality and time varying rates can be offered on an opt-in basis;
7. The Assessment shall include a sensitivity analysis for the most impactful cost and benefit uncertainties. The scope of work shall include an assessment of New Hampshire customer propensity to adopt opt-in time of use rates and New Hampshire geographic and demographic considerations for AMF deployment; and
8. The Assessment shall include a review of cybersecurity and confidentiality concerns associated with AMF.

(d) Quantification of benefits within the no AMR meters scenario identified in item (b) above shall be for illustrative purposes only and shall not be determinative of how costs and benefits would be quantified within any potential future proposals by PSNH.

(e) The Company, Staff, and the OCA shall collaborate in good faith and exercise best efforts to mutually agree upon the scope of work based on the foregoing provisions, and each shall have the opportunity to comment on the consultant's draft deliverables. The Company and consultant shall provide periodic updates to the Staff and the OCA and solicit input of the Staff and the OCA on material decisions during development of the assessment.

SECTION 5. MAJOR STORM COST RESERVE

5.1 The Company shall include $12 million annually in rates for the major storm reserve, consistent with the amount presently included in PSNH's rates.

5.2 Rather than implement a reconciling mechanism for storm costs, the Company shall be permitted to file for a separate, temporary amortization of storm costs for storm events that exceed $25 million per event which may include a request to recover costs for repair of damage due to such storm events through a surcharge (Storm Cost Adjustment Mechanism).

5.3 The Company shall continue to file reports on storm costs annually on May 1, consistent with current practice. Storms that have 100 percent of costs booked will be included in each storm report and any storms with costs that are not 100 percent booked will be included in the storm report in the year following the booking of all costs.

5.4 The Company shall annually offset the storm cost account #186430 directly with the balance in the funding account #228430, or a related successor account.

SECTION 6. VEGETATION MANAGEMENT PROGRAM

6.1 The Company shall be allowed to include $27.1 million annually in rates for vegetation management. Of this amount, $11.6 million annually is associated with enhanced tree trimming ("ETT") and hazard tree removal; $14.0 million annually is associated with scheduled maintenance trimming ("SMT"); and $1.5 million annually is associated with full-width right-of-way ("ROW") clearing.

6.2 The following terms apply to annual reconciliation of vegetation management program costs:

(a) The Company may request recovery of its actual annual vegetation management expenses up to 10 percent over, or any amount under, the total amount allowed in base rates ($27.1 million), credited to or recovered through the annual Regulatory Reconciliation Adjustment Mechanism as further described in Section 9 below.

(b) The Company shall submit a detailed vegetation management plan on or by November 15th each year starting in November 2020 for the following calendar year's vegetation work. The Company shall provide a summary of budgeted costs by program (i.e. ETT/Hazard Tree Removal, SMT and Full-Width ROW Clearing). Further details relating to the contents of the vegetation management plan are included as Appendix 3.

(c) The previous calendar year's actual vegetation activity shall be reconciled to the budget each year in an annual report submitted to the Commission by March 1. If the actual expense incurred in the prior calendar year is less than the amount in base rates ($27.1 million) the Company may request either to carry that amount into the next program year as an offset to the current year's expenditures or to return the under-spent amount to customers as a credit to the Regulatory Reconciliation Adjustment, subject to Commission approval. If the actual expense incurred in the prior calendar year is greater than the amount in base rates, the Company shall be allowed to recover amounts up to 10 percent of the amount in base rates through the Regulatory Reconciliation Mechanism ($2.71 million + $27.1 million = $29.81 million total), subject to Commission approval. Amounts greater than 10 percent over the amount in base rates shall not be recovered through the Regulatory Reconciliation Adjustment Mechanism or any other recovery mechanism.

(d) The first actual base rate reconciliation to be performed in the March 1, 2021 filing shall reconcile the costs from the period July 1, 2020 through December 31, 2020. The period January 1, 2020 through June 30, 2020 shall be reflected in the Company's recoupment adjustment.

6.3 The Company shall undertake a review of ETT and Hazard Tree Removal activities in an engineering review described in Section 11. The engineering review shall assess the benefits and costs of ETT and Hazard Tree Removal and make recommendations for targeted application of those programs and may result in adjustment to ETT/ Hazard Tree Removal budget after the review has been completed, as determined by the Commission pursuant to Section 11.5 of this Settlement.

SECTION 7. COST OF SERVICE ADJUSTMENTS

7.1 Since the time of restructuring, PSNH has been permitted to defer estimated environmental remediation/manufactured gas plant ("MGP") costs primarily relating to former generation sites.[8] The Company shall be allowed to recover the environmental reserve/MGP liability in the Stranded Cost Recovery Charge ("SCRC") rate at equal cents per kWh across customer classes rather than in distribution rates. To address the shift to the SCRC, the Company has removed an annual amortization of $2.3 million over four years as of December 31, 2018 from its proposed revenue requirement in this case and shall include it in the SCRC filing following approval of this Settlement Agreement. The amounts to be recovered in the SCRC shall be updated to reflect the actual deferred balance as of the time of the SCRC filing and be amortized over a four-year period. Future environmental costs shall be recovered on a current basis through the SCRC.

7.2 The Company shall use whole life depreciation.

7.3 On a monthly basis, the Company records an accrual for uncollectible expense representing an estimate of the amounts billed to customers but not paid and finally written off after all collection measures are exhausted. This monthly uncollectible expense accrual is calculated using a factor of historical account write-offs divided by revenue and multiplied by the current month retail revenue. Consistent with the Commission's previously approved method,[9] an amount equal

[8] Under the terms of the 1999 PSNH restructuring settlement agreement as approved by the Commission in Docket No. DE 99-099, and as approved in three subsequent rate proceedings (Docket Nos. DE 03-200, DE 06-028, and DE 09-035), PSNH was allowed to defer estimated MGP liabilities as they are accrued for future recovery. The estimated costs were recognized when PSNH's environmental scientists quantified the costs of site remediation, and 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, with appropriate carrying charges, is amortized to expense once recovery begins.

[9] As discussed in the testimony of Eric H. Chung and Troy M. Dixon, Bates pages 092-93, the Company calculated uncollectible expense by taking total test year retail revenue of $953,681,402 multiplied by a net write off ratio of 0.6571 percent, which represents a 3-year average of actual customer net write-offs as a percentage of retail revenues for the calendar years 2016 through 2018. This resulted in a total uncollectible expense of $6,266,640.

to 47.7 percent of uncollectible expense shall be allocated to and collected in the default Energy Service Rate, consistent with the Company's initial filing.

SECTION 8. COST OF CAPITAL

8.1 The Company shall be allowed a return on equity of 9.3 percent.

8.2 The Settling Parties have agreed that a capital structure of 54.4 percent equity and 45.6 debt shall be used for purposes of determining the Company's revenue requirement in this proceeding.

8.3 The Company shall be allowed a pre-tax weighted cost of capital of 6.87 percent.

8.4 The capital structure and overall cost of debt has been adjusted to reflect the issuance of $150 million in long-term debt in August 2020 at favorable rates, which reduced both PSNH's cost of debt and its overall cost of capital.

SECTION 9. ANNUAL REGULATORY RECONCILIATION ADJUSTMENT MECHANISM

9.1 The Company shall be authorized to implement an annual Regulatory Reconciliation Adjustment ("RRA") mechanism, which is intended to allow the Company to request recovery or refund of the limited set of costs identified below:

(a) Regulatory Commission annual assessments and consultants hired or retained by the Commission and OCA. In accordance with RSA 363-A:6, amounts above or below the total Commission assessment, less amounts charged to base distribution and default Energy Service, shall be recovered through the RRA. The amount in

That amount was then allocated 52.3 percent to distribution and 47.7 percent to energy service based on the ratio of test year distribution revenues to the sum of test year distribution revenues plus test year energy service revenues. This calculation is also provided in Attachment EHC/TMD-1 (Perm), Schedule EHC/TMD-8 (Perm), page 2. The allocation methodology was first established as a result of the settlement order in Docket No. DE 06-028 in which the Company was directed to allocate uncollectible expense using the proportion of distribution and energy service revenues.

base distribution rates pertaining to Commission assessments is $5,220,056 reflecting the fiscal year 2020 assessment to PSNH and excludes $10,000 which is to be recovered through the default Energy Service rate per Docket No. DE 14-238 and RSA 363-A:2, III. Additionally, legal and consulting outside service charges related to Commission approved special assessments assessed by the Commission to the Company for the expenses of experts employed by the Commission, Staff, and OCA pursuant to the provisions of RSA 365:37, II, RSA 365:38-a, and RSA 363:28, III shall also be recovered through the RRA. The Settling Parties acknowledge that current base distribution rates do not include any costs associated with consultants hired or retained by the Commission, Staff, and OCA, and any costs incurred within the calendar year shall be included in the RRA for recovery in the year following the year in which they are incurred. To the extent any such costs are recovered through another rate or method, they shall not be recovered through the RRA.

(b) Vegetation management program variances as described in Section 6 above. The RRA shall include the calendar year over- or under-collection from the Company's Vegetation Management Program. The over- or under-collection shall be credited or charged to the RRA on August 1 of the following year. The Company may request transfer of unspent amounts to the subsequent year's Vegetation Management Program budgets. The amount in base rates shall be $27.1 million for ETT, Hazard Tree Removal, ROW and SMT programs. The amount to be recovered in the RRA shall be based on the overall vegetation management program variance for the prior calendar year, rather than variances for individual activities within the overall program. The first RRA shall recover any over/under recoveries for the July 1, 2020 – December 31, 2020 vegetation management program associated with activities related to ETT, Hazard Tree Removal, and ROW clearing consistent with the expenditures noted in extension of the Temporary Rates Settlement Agreement as described in the Staff's March 24, 2020 letter in this docket. The first full year of the $27.1 million total vegetation management program reconciliation shall begin in the 2021 annual reconciliation.

(c) Property tax expenses, as compared to the amount in base rates. Consistent with RSA 72:8-e, property tax over- or under-recoveries as compared to the amount in base distribution rates shall be adjusted annually through the RRA. The amount included in base distribution rates for property tax expense shall be $45,186,407 based on property tax expense as of December 2019, normalized to exclude any credits related to property tax settlement proceeds for tax years preceding the test year. On an annual basis, actual property tax expense for the prior calendar year shall be compared against the amount in base rates and any variances will be reconciled through the RRA mechanism. Annual actual property tax expense shall be normalized to adjust for any credits received due to abatement settlement proceeds received for tax years preceding the test year. The RRA shall recover any over- or under- recoveries beginning in calendar year 2020.

(d) Lost-base distribution revenues associated with net metering, as calculated consistent with RSA 362-A:9, VII and the Commission's approved method in Order No. 26,029 (June 23, 2017) in Docket No. DE 16-576. The Settling Parties acknowledge that base distribution rates do not include any lost base distribution revenue associated with net metering for installations occurring on or after January 1, 2019. The amount of lost base distribution revenue shall be calculated based on the cumulative net metering installations from January 1, 2019 forward unless a different recovery methodology is adopted by the Commission in Docket No. DE 20-136, Recovery Mechanism and Rate Treatment for Net Metering and Group Host Costs, or any other docket. The RRA shall recover lost base distribution revenues beginning as of January 1, 2019.

(e) Storm cost amortization final reconciliation and annual reconciliation updated for actual cost of long-term debt. The RRA shall be used to reconcile the recovery amount of the storm costs through December 31, 2018, which are included for recovery as part of the temporary rate increase. Consistent with the temporary rate settlement, the $68.5 million currently being recovered over five years shall be reconciled based on final actual costs, including any audit adjustments, and to reflect the actual cost of debt over time. As part of the temporary rate settlement agreement, PSNH began amortizing the unrecovered storm costs as of December 31, 2018, which were estimated to be $68,474,355, over a five-year period beginning August 1, 2019. As of August 1, 2019, PSNH began applying a carrying charge on these storms equal to its embedded cost of long-term debt. On an annual basis through July 31, 2024, the RRA shall reconcile the amortization amount to adjust for the Company's actual cost of long-term debt interest rate as filed in the Company's Form F-1 on a quarterly basis.

9.2 The RRA shall be established annually based on a full reconciliation with interest for any over- or under-recoveries occurring in prior year(s). Interest shall be calculated at the prime rate, to be fixed on a quarterly basis and to be established as reported in *The Wall Street Journal* on the first business day of the month preceding the calendar quarter ("Prime Rate"). If more than one interest rate is reported, the average of the reported rates shall be used. Accumulated Deferred Income Taxes ("ADIT") shall not be included in the calculation of carrying charges on the over or under recovery of the RRA. ADIT reflects deferred income taxes caused by differences in accounting for expenses for tax purposes as compared to book accounting purposes. The carrying charges applicable to the RRA are intended to represent a proxy (Prime Rate) for the short-term cost to customers of over-collecting, or to the Company of under-collecting expenses. Because, unlike rate base ADIT, the items recovered through the RRA will generally turn around over a much shorter time period than plant-related ADIT, and because the Prime Rate is not intended to reflect the Company's weighted average cost of capital, the Company will not include ADIT in the calculation of carrying charges for over or under recoveries associated with the RRA. For purposes of billing under the alternative net metering tariff that became effective September 1, 2017, the RRA shall be considered part of the credit to net metering customers, unless determined otherwise by the Commission, either in Docket No. DE 20-136, Recovery Mechanism and Rate Treatment for Net Metering and Group Host Costs, or otherwise.

9.3 By March 1 of each year the Company shall submit a filing containing reports on PSNH's reliability statistics and vegetation management activities, and requesting the Commission open a new docket to consider the filing and other RRA issues. Such reports shall include information on reliability and vegetation management activities similar to information historically included in the Company's Reliability Enhancement Plan filings. Further detail regarding the report contents is provided in Appendix 4. The Company shall also include as part of this annual filing the proposed adjustment to the August 1 RRA associated with prior calendar year vegetation management activities, as described in Section 9.1(b) above. On or by May 1 of each year, the Company shall update its RRA filing with information pertaining to all other components of the RRA filing, along with supporting testimony and exhibits for rates effective August 1.

SECTION 10. STEP ADJUSTMENTS

10.1 The Company shall be allowed three step adjustments as follows:

(a) Step 1 shall reflect an increase to account for calendar year 2019 plant-in-service and shall be implemented concurrent with the increase in base rates in this proceeding. This first step shall be subject to the following conditions:

i. The revenue requirement shall be capped at $11 million.

ii. The step shall include only allowed projects and annual projects and programs closed to plant in 2019, excluding new business/growth-related projects.

iii. The rate for the first step shall be designed to recover the value of the step adjustment from January 1, 2021 through July 31, 2021. Beginning August 1, 2021 (the rate effective date of the second step adjustment), the rate shall be adjusted going forward to reflect a 12-month calendar recovery of the first step.

iv. The projects and programs that may be included in the step are identified in the listing attached as Appendix 5.

(b) Step 2 shall reflect an increase for calendar year 2020 plant-in-service and shall be effective August 1, 2021, subject to the following conditions:

i. The revenue requirement associated with this step shall be capped at $18 million.

ii. This step shall include only allowed projects/programs closed to plant in 2020, excluding new business/growth-related projects.

iii. The projects and programs that may be included in this step are identified in the listing attached as Appendix 5. The Settling Parties agree that the Company may substitute projects prior to the commencement of the review period if projects identified in this appendix are not deployed.

(c) Step 3 shall reflect an increase for calendar year 2021 plant-in-service to be effective August 1, 2022 and shall be subject to the following conditions:

i. The revenue requirement associated with this step shall be capped at $9.3 million.

ii. This step shall include only allowed projects and programs closed to plant in 2021, excluding new business/growth-related projects.

10.2 For the first step, the following process shall apply. In recognition of the limited time to make changes to the Company's documentation as well as the historical nature of the projects in issue, for the first step increase related to capital investments made in 2019, the Company shall make a filing at or around the time of the filing of this Settlement Agreement with testimony and supporting information describing the capital projects placed in service in calendar year 2019, as well as testimony and supporting information describing the proposed rate impact, using the documentation available at the time of the filing. In addition, the Company's initial filing shall provide a summary list of capital projects, excluding new business projects, showing, at least: the project name and description; initial budget by project; variances from the initial budget; and final actual costs. After the Company's initial filing, and upon the request of Staff, the Company shall provide further information related to a sampling of the Company's projects, including but not limited to Project Authorization Forms, Supplemental Request Forms, and work order cost detail summarized at the project level by cost category over the life of the project.

10.3 For the second and third steps the following process shall apply. The Company shall make a filing by May 1, 2021, for the second step increase, with rates effective August 1, 2021 and the Company shall make a filing by May 1, 2022, for the third step increase, with rates effective August 1, 2022. Each filing shall include, at least, the following documentation and process steps:

(a) The Company shall provide the amount of the investments to be included in the step increases (by project) and detailed project descriptions including the initial budget, the final cost, and the date on which each project was booked to plant in-service.

(b) For each project, all project documents will be provided including, but not limited to, Project Authorization Forms, Supplemental Request Forms, and work order cost detail summarized at the project level by cost category over the life of the project.

(c) After the Company's initial filing, and upon request of Staff, the Company shall provide additional information to aid in review of the initial filings.

(d) For the second and third step increases, the Company shall conform the documentation to the template to be agreed to in accordance with Section 3 above, to the extent possible and subject to limitations that may exist in relation to retroactive application of a new format.

(e) For all steps, including the first step, the Company agrees that if the actual costs are less than budgeted amounts, the actual amounts shall be used to calculate the step adjustments. If the actual cost of the capital additions exceeds the budgeted amounts, the Company may seek recovery of the excess through the step adjustment process, up to the specified step adjustment caps. If not addressed through the step adjustment, the Company may seek recovery in its next rate case.

(f) The revenue requirement for the step adjustments shall be calculated in a manner similar to that used in the Company's initial filing at Bates 313-320 (Attachment EHC/TMD-3 (Perm)), except that it will exclude recovery of Enterprise IT Project costs, and Union Contractual Adjustments.

(g) With respect to timing of filing documentation and the step process, the Company shall file the required documentation and supporting information on or by May 1 of each year for rates effective as of August 1 of each year. The Company acknowledges that: (1) Staff and the OCA require at least 90 days to review the each step; and (2) Staff and the OCA agreement to step adjustments does not foreclose full prudence review during analysis of each step adjustment, including the Company's decision to make an investment and the management of each project.

(h) Incremental equipment/project costs directly resulting from the Company's recently revised SYSPLAN 008 and SYSPLAN 010 shall be ineligible for recovery within these steps. Project costs relating to asset condition may be recoverable.

10.4 All step increases shall be subject to Staff audit and reconciliation based on the results of the audit, as approved by the Commission.

10.5 Nothing in this Settlement Agreement shall preclude the Settling Parties from disputing the prudence of individual investments requested for recovery within the step increases.

10.6 The Company shall not request recovery of any capital costs associated with plant placed in service outside of the above-described step adjustments until the Company's next distribution rate case filing, which shall be based on a test year ending no sooner than December 31, 2022, and which shall be filed no earlier than the first quarter of 2023.

SECTION 11. ASSESSMENT OF FUTURE DISTRIBUTION INFRASTRUCTURE NEEDS

11.1 The Company's initial petition included proposals related to certain practices and planned capital investments related to system resilience, and the potential acceleration of those investments under what it described as a Grid Transformation Enablement Program. Several parties filed testimony containing observations and concerns regarding those investments. In light of these observations and concerns, at the Company's expense, the Company shall hire an engineering firm to perform a condition assessment of the PSNH distribution infrastructure, including substations, to provide recommendations related to the Company's short and long-term system needs consistent with the requirements of least-cost integrated resource planning.

11.2 As part of the condition assessment, the engineering firm shall review the cost-effectiveness of using: (1) steel poles in right-of-way (ROW); (2) Class 2 poles as a standard pole; (3) composite cross arms; (4) relocated ROW facilities; (5) spacer cable and tree wire; and (6) reconductoring of under-sized wire. The assessment shall also include ETT and Hazard Tree Removal activities.

11.3 The Company intends to continue with its current practices as defined in Section 11.2 above pending the engineering firm's assessment and substantiation of those practices as consistent with good utility practice and least-cost planning, subject to Commission determination.

11.4 At the Company's expense, the Company shall conduct a comprehensive survey of PSNH's customers regarding their prioritization of reliability and resiliency versus cost. The Company shall work collaboratively with Staff and the OCA on development of the survey instruments.

11.5 The New Hampshire-specific engineering assessment and survey shall be submitted by March 31, 2021 as supplemental testimony in the docket for the Company's 2020 least-cost integrated resource plan (LCIRP) filing.

11.6 The Settling Parties agree the Commission may contract with a consultant to review the results of the PSNH consultant's engineering assessment, and perform other engineering work as needed. The costs of such a review shall be recoverable through the RRA mechanism.

SECTION 12. FEE FREE CREDIT/DEBIT CARD PAYMENT

12.1 In recognition of a general transition to "cashless" business transactions, with customers both expecting and preferring to use their credit/debit cards to pay their bills through mobile or on-line applications, as well as customer dissatisfaction with present bill payment options. PSNH proposed implementing a "fee free" option through its payment processing vendor that would allow customers to pay their monthly bills with a credit/debit card without incurring a transaction fee. The Settling Parties agree that PSNH shall implement a modified version of this proposal as described below.

12.2 PSNH shall implement a fee free credit/debit card payment system through its third-party vendor consistent with the proposal described in the testimony of PSNH witness Penelope McLean Conner, subject to the following:

(a) At this time, fee free credit/debit card payments shall be implemented as an option for residential customers and shall only be available for one-time (i.e., not automatic recurring) payments. Customers who wish to pay by credit or debit card each month shall be required to enter their credit or debit card payment information for each payment made.

(b) PSNH shall monitor the adoption rate by customers and shall report on the adoption rate to the Staff and OCA. Based upon the information reported, PSNH shall work with the Staff and OCA to determine whether amendments to the fee free program, such as expansion to commercial customers or to allow for recurring payments, should be recommended to the Commission for approval.

(c) Information on the updated costs and adoption rates of the fee free program are included in Appendix 6.

12.3 The Company may recover $375,000 of program-related costs in base rates annually beginning January 1, 2021, subject to reconciliation at the time of the Company's next rate case, with carrying charges on the over- or under-recovered balance calculated using the Prime Rate. If the actual costs resulting from customers' adoption of the fee free option exceed the $375,000 allowed in rates in the first year, the Company shall increase the amount in rates to an amount reflecting the estimated cost, but not more than $520,500, effective February 1, 2022. Testimony and supporting materials relating to such increase, if requested, shall be included in the materials submitted with the Company's SCRC filing for effect on February 1, 2022.

SECTION 13. NEW START - ARREARS MANAGEMENT PROGRAM

13.1 Consistent with programs currently offered by PSNH's affiliates in Massachusetts and Connecticut, PSNH proposed implementing the "New Start" program in New Hampshire. New Start is an arrears management program that provides payment assistance for qualifying residential customers struggling with past due utility bills where for every required monthly payment an enrolled customer makes to the Company, a portion of their past due balance will be forgiven. The intent of the program is to: enable the customer to develop consistent bill payment habits; protect the customer from service disconnection while participating in the program; and enable the customer to get a fresh start as the arrears are forgiven with each payment made. The Settling Parties agree that PSNH shall implement the New Start program in New Hampshire.

13.2 Initial programming costs for implementing the New Start program shall be recovered in base rates, rather than through the RRA. The Company may recover $340,000 of program start-up costs in base rates annually beginning January 1, 2021, subject to reconciliation at the time of the Company's next rate case, with carrying charges on the over-or under-recovered balance calculated using the Prime Rate. The Settling Parties acknowledge that implementing the program will require substantial programming changes, and customer and community education, and that, at present, such implementation is targeted to occur in the first quarter of 2022.

13.3 The Company shall be permitted to recover $1,077,356 in base rates annually beginning February 1, 2022, subject to reconciliation at the time of the Company's next rate case, with carrying charges on the over- or under-recovered balance calculated using the Prime Rate. This recovery shall fund a reserve account for funds collected through rates for the program. Testimony and supporting materials relating to implementing this adjustment to base rates shall be included in the materials submitted with the Company's SCRC filing for effect on February 1, 2022.

13.4 A description of the program rules is set out more fully in Appendix 7 and includes the following general requirements:

(a) $12,000 per customer annual cap on forgiveness.

(b) The program shall be available to any customer whose account is coded "financial hardship" consistent with the Commission's Puc 1200 rules, and whose account has a balance of $150 or more that is at least 60 days past due.

13.5 The New Start program shall initially be designed for implementation in line with the description in Appendix 7. The Company shall convene a stakeholder group within 60 days of the Commission's approval of this settlement agreement to develop a comprehensive program design for the New Start program and to assist in the long-term monitoring and evaluation of the program. The stakeholder group shall be open to interested members of the Settling Parties, and any other interested parties.

The stakeholder group shall not be considered as attached to the Commission, and the Staff will serve as a non-voting member of the group. Staff will attend meetings at its discretion.

The stakeholder group shall file a report with the Commission within 120 days of the final order in this proceeding to recommend a comprehensive program design. The members of the stakeholder group shall work in good faith through the stakeholder group process to reach consensus on the design of the program. The report shall include the recommendations of the group and shall describe areas of consensus and any areas of disagreement. In cases of disagreement, a disagreeing member may make its own recommendations to the Commission concerning the program design

The stakeholder group shall determine its purposes and activities, which may include monitoring the program, addressing communication and training for social service agencies, and reviewing communications for customers pertaining to the program. Following completion of agreed business design requirements, the stakeholder group may meet periodically as it deems necessary and proper to review the program and make recommendations on further refinements while maintaining the core program design.

13.6 The Company shall develop a plan and format for quarterly reporting to be included in the stakeholder group report described in Section 13.5 above, utilizing the metrics described in Appendix 7. Such reports shall be filed with the Commission and provided to the stakeholder group on a quarterly basis until such time the stakeholder group determines a different reporting time.

SECTION 14. TARIFFS AND RATE DESIGN

14.1 The Settling Parties agree that the updates to the fees and charges as described in the updates to the Terms and Conditions of the Company's tariff, as well as the updates to the fees and charges pertaining to competitive electric power suppliers, provided in its initial filing should be approved as filed.

14.2 There shall be no tariff provision allowing default Energy Service customers to block incoming enrollments from competitive suppliers as had been proposed in the Company's initial filing.

14.3 The Company shall propose a symmetrical decoupling mechanism in its next rate case. The Settling Parties acknowledge that provision does not necessarily constitute support of decoupling in principle nor support of any particular version of decoupling by any party, and does not prejudice any party's right to oppose, or to seek to modify, such proposal in the next rate case.

14.4 The Company's customer charge shall remain at the level implemented pursuant to the Temporary Rates Settlement Agreement until the Company's next rate case. Specifically, except for outdoor lighting rates, the base rate increases and any surcharges or sur-credits provided for in this Settlement, shall be collected solely through changes in consumption or demand charges.

14.5 The Settling Parties agree that the revenue increase shall be allocated in equal proportionality among the classes. For clarity, the Company shall directly assign costs to the outdoor lighting classes, and then allocate the remainder of the costs to each customer class on an equal percent basis. Specifically, the Company shall reduce the outdoor lighting class revenue allocation of costs by $1.356 million and then allocate the total permanent rate increase in equal proportionality among all rate classes. The calculation of the allocation is included in Appendix 10.

14.6 Within six months of the Commission's approval of this Settlement Agreement, the Company shall propose amendments to its tariff to revise its optional time-of-day rate for residential customers. Such proposal shall include, but not be limited to, a two-period rate structure consisting of peak and off-peak periods, with a peak period lasting no more than eight hours. PSNH shall collaborate with interested members of the Settling Parties and other stakeholders in developing the proposal.

14.7 The Company agrees to phase out declining block rates for all rate classes where such rates exist. Half of the differential between the relevant blocks will be eliminated within this rate case, and the remaining half will be eliminated as part of the Company's next rate case.

14.8 The Company shall make the following changes to its tariff relative to outdoor lighting:

(a) The assumed hours of operation contained in PSNH's Rate OL and Rate EOL shall be adjusted to one-half hour after sunset to one-half hour before sunrise consistent with those times for Concord, New Hampshire specified in the 2020 edition of the Farmer's Almanac and data available from the U.S. National Oceanographic Atmospheric Administration (NOAA). Midnight lighting hours shall be adjusted accordingly. The relevant adjustments shall be made available once necessary programming and bill changes have been implemented.

(b) PSNH's Rate EOL will also be amended to include language allowing for advanced lighting controls. The relevant adjustments shall be made available once necessary programming and bill changes have been implemented.

(c) PSNH shall create a new rate which will align more closely with the language of the Liberty Utilities LED-2 rate to allow additional flexibility and options for municipalities to install advanced lights and lighting controls, and to allow municipalities to own and maintain the streetlights in their communities. PSNH shall work with interested parties on final tariff language to implement this provision with a goal of having new tariff language submitted to the Commission for approval during the first quarter of 2021. A framework for this new rate offering is set out in Appendix 8. At the time the new tariff language is submitted, the

Company will also specify the effective dates of the changes set out in Sections 14.8(a) and (b) above.

SECTION 15. RECOUPMENT

15.1 The Excess Deferred Income Tax ("EDIT") credit associated with Protected Property and Unprotected Pension (amortized over 10 years) shall be incorporated as a component of base rates, resulting in a reduction of the revenue deficiency of approximately $5.1 million.

15.2 To the extent the Company experiences higher arrearages than anticipated due to the on-going pandemic, those arrearages shall be addressed in a separate docket specific to the costs and issues of the pandemic.

15.3 For EDIT balances not reflected in permanent base rates, the Company shall establish a tax sur-credit mechanism to ensure customers receive the full amount to which they are entitled and that the Company does not credit more than it owes. The sur-credit mechanism will incorporate the following:

(a) 2018/2019 Federal EDIT balance of $13.3 million will offset recoupment amount.

(b) Remaining 5-year Federal EDIT balance of $5.2 million.

(c) Total 5-year NH EDIT balance of $4.9 million.

(d) Amortize the total balance to be returned via the Tax Cuts and Jobs Act ("TCJA") sur-credit so that the liability is extinguished by the end of 2023.

(e) See Appendix 1 for calculation of recoupment amount, net of $13.3 million and the TCJA sur-credit.

SECTION 16. ELECTRIC VEHICLES

16.1 The Settling Parties acknowledge that matters of rate design regarding electric vehicles have been excluded from this rate case and are only included by reference in this Settlement Agreement with respect to one or more future filings by the Company in a separate docket, as discussed in paragraph 16.2(b) below.

16.2 With respect to make-ready investments supporting electric vehicle charging infrastructure, the Settling Parties agree to the following:

(a) Within four months following the Commission's approval of this Settlement Agreement, PSNH shall file a proposal for make-ready investments supporting electric vehicle charging infrastructure in New Hampshire and request that the Commission open a new docket to consider the proposal;

(b) As part of the filing referenced in (a) above, PSNH shall include a proposal for an alternative to demand charges for electric vehicle charging rates unless the Commission determines otherwise in the adjudicative proceeding announced in Order No. 26,394 (August 18, 2020) in Docket No. IR 20-004; and

(c) PSNH shall collaborate with interested members of the Settling Parties in developing the proposal referenced in (a) above and other stakeholders requesting to be included.

16.3 The Settling Parties expressly acknowledge that this Settlement Agreement does not include or contemplate any specific cost recovery relating to any proposed deployment or development of electric vehicle charging infrastructure. In any future proposal by the Company to support electric vehicle charging infrastructure, the Company shall include, at a minimum, information on the costs and benefits of such infrastructure which identifies the customers or customer classes to which the costs and benefits apply. The Company shall bear the burden of justifying any cost recovery proposed, and any of the Settling Parties, or other participants to the future proceeding, are free to take any position they choose relative to the proposed infrastructure investment and any proposed cost recovery.

SECTION 17. EFFECTIVE DATE

17.1 This Settlement Agreement is subject to and shall become effective upon Commission approval, with new permanent rates to become effective as of January 1, 2021. The Settling Parties shall use best efforts to obtain Commission approval on or before November 28, 2020.

SECTION 18. GENERAL PROVISIONS

18.1 A timeline of the events and filings contemplated by this Settlement Agreement is included as Appendix 11.

18.2 A revised tariff intended to incorporate the provisions of this Settlement Agreement is included as Appendix 9.

18.3 This Settlement Agreement is expressly conditioned upon the Commission's acceptance of all its provisions, without change or condition. If the Commission does not accept this Settlement Agreement in its entirety, without change or condition, or if the Commission makes any findings that go beyond the scope of this Settlement Agreement, and any of the Settling Parties notify the Commission within five business days of their disagreement with any such changes, conditions, or findings, the Agreement shall be deemed to be withdrawn, in which event it shall be deemed to be null and void and without effect, shall not constitute any part of the record in this proceeding, and shall not be relied on by Staff or any party to this proceeding or by the Commission for any other purpose.

18.4 Under this Settlement Agreement, the Settling Parties agree to this joint submission to the Commission as a resolution of the issues specified herein only.

18.5 The Settling Parties agree that the Commission's approval of this Settlement Agreement shall not constitute continuing approval of, or precedent for, any particular principle or issue, but such acceptance does constitute a determination that the adjustments and provisions stated in their totality are just and reasonable and consistent with the public interest and that the rates contemplated will be just and reasonable under the circumstances.

18.6 This Settlement Agreement shall not be deemed an admission by any of the Settling Parties that any allegation or contention in this proceeding by any other party, other than those specifically agreed to herein, is true and valid. This Settlement Agreement shall not be construed to represent any concession by any Settling Party hereto regarding positions taken with respect to the Company's proposals in this docket, nor shall this Settlement Agreement be deemed to foreclose any Settling Party in the future from taking any position in any subsequent proceedings. The amounts associated with each of the settlement adjustments detailed herein are liquidated amounts that reflect a compromise of all the issues in this proceeding.

18.7 The pre-filed testimony and supporting documentation previously provided in this proceeding are not expected to be subject to cross-examination by the Settling Parties, which would normally occur in a fully litigated case. The Settling Parties agree that all pre-filed testimony and supporting documentation should be admitted as full exhibits for the purpose of consideration of this Settlement Agreement, and be given whatever weight the Commission deems appropriate. Consent by the Settling Parties to admit all pre-filed testimony without challenge does not constitute agreement by any of the Settling Parties that the content of the pre-filed testimony is accurate or that the views of the witnesses should be assigned any particular weight by the Commission. The resolution of any specific issue in this Settlement Agreement does not indicate the Settling Parties' agreement to such resolution for purposes of any future proceedings, nor does the reference to any other document bind the Settling Parties to the contents of, or recommendations in, that document for purposes of any future proceeding. The Commission's approval of the recommendations in this Settlement Agreement shall not constitute a determination or precedent with regard to any specific adjustments, but rather shall constitute only a determination that the rates resulting from, and other specific conditions stated in this Settlement Agreement are just and reasonable. The Settling Parties agree to forego cross-examining witnesses regarding their pre-filed testimony and, therefore, the admission into evidence of any witness's testimony or supporting documentation shall not be deemed in any respect to constitute an admission by any party to this Agreement that any allegation or contention in this proceeding is true or false, except that the sworn testimony of any witness shall constitute an admission by such witness.

18.8 The rights conferred and the obligations imposed on the Settling Parties by this Settlement Agreement shall be binding on or inure to the benefit of any successors in interest or assignees as if such successor or assignee was itself a signatory party. The Settling Parties agree to cooperate in advocating that this Settlement Agreement be approved by the Commission in its entirety and without modification.

18.9 The discussions that produced this Settlement Agreement have been conducted on the understanding that all offers of settlement and settlement discussions relating to this docket shall be confidential, shall not be admissible as evidence in this proceeding, shall be without prejudice to the position of any party or participant representing any such offer or participating in any such discussion, and are not to be used in connection with any future proceeding or otherwise. The content of these negotiations, including any documents prepared during such negotiations for the purpose of reaching a settlement, shall be privileged and all offers of settlement shall be without prejudice to the position of any party presenting such offer.

18.10 This Settlement Agreement may be executed by facsimile and in multiple counterparts, each of which shall be deemed to be an original, and all of which, taken together, shall constitute one agreement binding on all Settling Parties.

SECTION 19. CONCLUSION

19.1 The Settling Parties affirm that the proposed Settlement Agreement will result in just and reasonable rates and should be approved by the Commission.

[signature pages follow]

Dated: October 9, 2020

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

By:______________________________
Matthew J. Fossum
Its Attorney

Dated: October 9, 2020

Staff of the New Hampshire Public Utilities Commission

By:______________________________for
Suzanne Amidon
Its Attorney

Dated: October 9, 2020

Office of the Consumer Advocate

By: ______________________________________
D. Maurice Kreis
Consumer Advocate

Dated: October 9, 2020

Clean Energy New Hampshire

By: ______________________________________
Elijah Emerson
Its Attorney

Dated: October 9, 2020

AARP New Hampshire

By: ______________________________________
John Coffman/Joseph Donahue
Its Attorney

Dated: October 9, 2020

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

By: ______________________________

Matthew J. Fossum
Its Attorney

Dated: October 9, 2020

Staff of the New Hampshire Public Utilities Commission

By: ______________________________

Suzanne Amidon
Its Attorney

Dated: October 9, 2020

Office of the Consumer Advocate

By: ______________________________

D. Maurice Kreis
Consumer Advocate

Dated: October 9, 2020

Clean Energy New Hampshire

By: ______________________________

Elijah Emerson
Its Attorney

Dated: October 9, 2020

AARP New Hampshire

By: ______________________________

John Coffman/Joseph Donahue
Its Attorney

Dated: October 9, 2020

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

By: ______________________________
Matthew J. Fossum
Its Attorney

Dated: October 9, 2020

Staff of the New Hampshire Public Utilities Commission

By: ______________________________
Suzanne Amidon
Its Attorney

Dated: October 9, 2020

Office of the Consumer Advocate

By: ______________________________
D. Maurice Kreis
Consumer Advocate

Dated: October 9, 2020

Clean Energy New Hampshire

By: ______________________________
Elijah Emerson
Its Attorney

Dated: October 9, 2020

AARP New Hampshire

By: ______________________________
John Coffman/Joseph Donahue
Its Attorney

Dated: October 9, 2020

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

By: ______________________________
Matthew J. Fossum
Its Attorney

Dated: October 9, 2020

Staff of the New Hampshire Public Utilities Commission

By: ______________________________
Suzanne Amidon
Its Attorney

Dated: October 9, 2020

Office of the Consumer Advocate

By: ______________________________
D. Maurice Kreis
Consumer Advocate

Dated: October 9, 2020

Clean Energy New Hampshire

By: ______________________________
Elijah Emerson
Its Attorney

Dated: October 9, 2020

AARP New Hampshire

By: John Coffman/Joseph Donahue
John Coffman/Joseph Donahue
Its Attorneys

Dated: October 9, 2020

The Way Home

By: ______________________
Raymond Burke
Its Attorney

Dated: October 9, 2020

Acadia Center

By: ______________________
Amy Boyd
Director of Policy and Senior Attorney

Dated: October 9, 2020

NH Department of Environmental Services

By: ______________________
Christopher Skoglund
Climate and Energy Program Manager

Dated: October 9, 2020

Walmart, Inc.

By: ______________________
Melissa Horne
Its Attorney

Dated: October 9, 2020

ChargePoint, Inc.

By: ______________________
Melissa Birchard
Its Attorney

Dated: October 9, 2020

The Way Home

By: ______________________________________

Raymond Burke
Its Attorney

Dated: October 9, 2020

Acadia Center

By: ______________________________for

Amy Boyd
Director of Policy and Senior Attorney

Dated: October 9, 2020

NH Department of Environmental Services

By: ______________________________for

Craig A. Wright
Director, Air Resources Division

Dated: October 9, 2020

Walmart, Inc.

By: ______________________________for

Melissa Horne
Its Attorney

Dated: October 9, 2020

ChargePoint, Inc.

By: ______________________________for

Melissa Birchard
Its Attorney

DE 19-057 PSNH Rate Case

Settlement Agreement List of Appendices

1. Recoupment Calculation
2. Business Process Audit Scope
3. Vegetation Management Plan Description
4. Reliability and Vegetation Management Report Description
5. Step Adjustments – Project lists for 2020 and 2021
6. Fee Free Information
7. New Start Information
8. EOL-2 Streetlight Tariff Framework
9. Revised Tariff – Tariff No. 10
10. Rate Allocation and Bill Impact Information
11. Timeline of Filings and Events from Settlement

PSNH Rate Case 19-057

Appendix 1

	Temporary Rate Recoupment Calculation		Final Settlement ($000s)	
1	Revenue Deficiency per Settlement	$	44,987	Revised Settlement Revenue Deficiency
2	EDIT Credit in Permanent Rates		5,149	EDIT for Temporary Rate Period to be Refunded as Offset to Recoupment
3	Adjust Fee Free to reflect 1/1/21 Implementation		(375)	Remove Fee Free for Temporary Period
4	Adjust New Start to reflect 1/1/21 Implementation		(502)	Remove New Start Asset Amortization
5	Rev Req net of EDIT	$	49,259	Line 1 - Line 4
6	18 Month Factor		1.50	
7	Permanent Revenues for the 18 Month Temporary Rate Period	$	73,888	
8				
9	Revenue Deficiency per Temporary Rates	$	31,006	Temporary Rate Settlement Increase (28,278 adj to 31,006 to recover 12 months over 11 months)
10	Add Back 12 month TCJA Credit		13,151	Eliminate TCJA Credit from Temp Rate to avoid recovering the credit through recoupment
11	Temporary adjusted for TCJA Credit	$	44,157	Line 9 + Line 10
12	Collection Period (Months)		17	
13	Temporary Rates Collected	$	62,556	Line 11 / 12months * Line 12
14				
15	**Unadjusted Temporary Rate Shortfall**	**$**	**11,332**	Line 9 less Line 13
16				
17	TCJA Credit under recovery	$	5,565	TCJA Credit under recovery caused by extension of temporary rate period
18	Adjust Vegetation Mgmt for Recoupment (Table 2)		1,631	Limit recoupment to Veg Mgmt in Temp Rates
19	Vegetation Mgmt Underspend (07/19-12/19)		(11)	Actual Spend of $7.689M vs $7.7M in Temp Rates for 7/19-12/19
20	Total Recoupment	$	18,517	Sum of lines 17-19
21	Recover Final Year of Consultant Amortization		337	Add back to recoupment; eliminated from revenue requirement
22	EDIT Adjustment		(13,258)	Recoupment Offset per Staff Schedule
23	Net Recoupment	$	5,596	Sum of lines 20-22

Table 1: To reconcile TCJA credit provided to customers in temp rates vs TCJA credit owed to customers

24	TCJA/REP Credit per Temporary Rates	$	13,151	12 month credit included as offset to Temporary Rate increase
25	Extend to 18/17 Months		1.42	Extends Annual Credit to 18 Month Temporary Rate Period
26	Total TCJA Credit during Temporary Rate Period	$	18,631	Line 24 * Line 25
27	Actual TCJA / REP reconcilation		13,066	Schedule 1, page 2 of APPENDIX 1 - filed as part of 7/22/20 communication
28	Net Overrefund During Temporary Rate Period	$	5,565	Line 26 - Line 27

Table 2: To eliminate impact of Vegetation Management on recoupment consistent with Temporary Rate Settlement Agreement

29	Veg Mgmt for Permanent Rates		13,100	$11.7M ETT/ETR + $1.4M ROW
30	18 Month Factor		1.50	
31	Veg Mgmt Revenue Allowed Under Permanent Rates	$	19,650	
32				
33	Reconcilable Veg Mgmt from Temp Rates	$	15,022	ETT/ETR As Per Temporary Rate Settlement
34	Extend to 18/17 Months		1.42	Extends Annual Credit to 18 Month Temporary Rate Period
35	Veg Mgmt Under Temporary Rates for Full Temporary Rate Period	$	21,281	
36	Add Back to Recoupment Calculation	$	1,631	Line 35 - Line 31

Table 3: Calculation of Surcredit refunds

37	Year 1-2 Federal EDIT w/Gross Up	$	(13,258)	Per Staff Worksheet "Offset Recoupment"
38	Year 3-5 Remaining 5 Year EDIT Balance (Federal) w/Gross Up		(5,153)	Per Staff Worksheet "Surcredit Refund"
39	Year 1-5 Remaining 5 Year EDIT Balance (State) w/Gross Up		(4,887)	Per Staff Worksheet "Surcredit Refund"
40	Total Available EDIT	$	(23,298)	
41	EDIT Utilized For Recoupment		(13,258)	Year 1-2 Federal EDIT w/Gross Up
42	EDIT for Surcredit	$	(10,040)	

Table 4: To calculate net of Recoupment and TCJA Surcredit

43	Recoupment	$	5,596	Line 23
44	TCJA Surcredit		(5,020)	Line 42 / 2 years (2021 through 2023)
45	Net year 1 impact of TCJA Surcredit and Recoupment	$	576	

DE 19-057 PSNH Rate Case – APPENDIX 2

Business Process Review Audit

As specified in Section 3.2 of the Settlement, the Company agrees to a business process audit of the Company to be conducted and overseen by Staff. That business process audit shall be conducted consistent with the process and scope set out in this attachment as specified below.

Process:

1. Staff will draft the RFP with input from the Company.

2. Company, Staff, and OCA will work collaboratively to draft the qualifications that will go into the RFP.

3. The consultant will be hired and supervised by the Commission and Staff, and paid for by the Company.

4. Staff and the Company will have an opportunity to review and comment on the consultant's final report prior to filing with the Commission.

Scope:

1. Review and assessment of the Company's capital planning, budgeting, approval, and management oversight, including:

    a. Company's budgeting and approval process for capital expenditures.

    b. Company's information systems used in work planning, tracking, and accounting.

    c. Initial project design and development of budgets, cost estimates, revised budgets and budget variances.

    d. Internal accounting for capital projects and administrative support.

    e. Decision making by project managers involving design changes, engagement and hiring of outside contractors and the Company's oversight of contractors.

    f. Decision making by project managers in addressing and controlling project costs including factors that necessitate the involvement of upper management.

    g. Reviews by upper management of project costs and cost overruns and the application of cost controls.

    h. Compliance of the above-listed items with good utility practices.

2. Review and evaluation of capital project documentation, including:

a. Compliance with documentation policies and filing requirements.

b. Initial project assessment and analysis in the PAF including consideration of known and foreseeable costs and risks.

c. Use of Supplement Requests, including root cause analysis and lessons learned.

d. Source documentation and supporting documentation.

e. Recommendations for improving and enhancing the above documentation process.

3. Selective Project Review: The consultant will select a sample of capital projects for 2020 and 2021 to be included as a part of its examination and testing involving the above listed processes.

DE 19-057 PSNH Rate Case – APPENDIX 3

Vegetation Management Plan

As required by Section 6.2 of the Settlement, in November of each year PSNH is to file a proposed vegetation management plan setting out the proposed vegetation management work for the coming calendar year. That plan filing shall include the following:

A. A summary of budgeted costs by program (i.e. ETT/Hazard Tree Removal, SMT and Full-Width ROW Clearing).

B Detailed information on each program as follows:

i. ETT/Hazard Tree Removal: Town; Circuit Number; Total Circuit Miles; Scheduled Circuit Miles; and Circuit Ranking by SAIDI and SAIFI (Tree Related only).

ii. SMT (Scheduled Maintenance Trimming, Mid-Cycle Trimming, Side Trimming and Customer Request Work, Hot Spot / Trouble Work, and Maintenance ETT): Town; Circuit Number; Total Circuit Miles; and Scheduled Circuit Miles.

iii. SMT (ROW Maintenance Mowing and Side Trimming): ROW Number; ROW Name; Voltage; and Total Acreage; and the percentage of the clearing attributable to distribution if transmission ROW.

iv. ROW Clearing: ROW Number; ROW Name; Voltage; and Total Miles; ROW Width; and the percentage of the clearing attributable to distribution if transmission ROW.

DE 19-057 PSNH Rate Case – APPENDIX 4

Reliability and Vegetation Management Reports

As required by Section 9.3 of the Settlement, by March 1 of each year PSNH is to file reports of its reliability statistics and vegetation management activities for the prior calendar. Each report may be filed separately, but both shall be filed no later than March 1. Those reports shall include the following information:

For the Reliability Statistics Report:

1. Executive Summary

2. Reliability graphs (IEEE Criteria)
    a. SAIFI, SAIDI, CAIDI, CIII – Distribution System Only
    b. CAIFI, CTAIDI – Distribution System Only[1]
    c. SAIFI, SAIDI, CAIDI, CIII – Distribution System – Tree Related
    d. SAIFI, SAIDI, CAIDI, CIII – Distribution (excluding Substation) Equipment Failure
    e. SAIFI, SAIDI, CAIDI, CIII – Substation Equipment Failure
    f. SAIDI (MED) - Storm MED; Equipment Failure MED; Other MED (Specify)
    g. SAIDI and SAIFI by cause (Pie Charts)

3. O&M Activities related to reliability for prior year ($ allocated and $ spent if available)
    a. Overhead circuit patrols (circuits to be patrolled planned and circuits patrolled actual)[2]
        i. Indicate circuits and type of planned patrol
    b. Underground circuit patrols including fault indicator replacements
    c. Pole inspections (Number of poles targeted, and number of poles completed)
        i. Include % of poles determined to be condemned
    d. NESC Maintenance Repairs (locations targeted, and locations completed)

4. Capital activities related to reliability for prior year ($ allocated and $ spent if available)

[1] Due to Eversource's high penetration of SCADA enabled switches, CAIFI and CTAIDI presents additional representation of interrupted duration and frequency.
[2] Circuits that are patrolled more than once are considered only one entry and circuits patrolled during emergency outage are not included. Circuit miles patrolled for this report are for planned patrols.

a. Reject pole replacement (number of poles targeted for replacement and poles replaced)
b. Underground Cable Repl. (# of locations and footage targeted and footage completed)
c. Other capital reliability projects (over $100k. Will not include Annual projects) Typical projects include circuit ties, obsolete equipment replacement, reconductoring to covered conductor, 4 kV conversions, pole top distribution automation, etc. (Description including reliability impact eg. $/ΔCI or $/ΔCMI)

5. Worst Performing Circuit List (Worst 50)
    a. SAIDI and SAIFI. Circuit SAIDI and SAIFI can be provided as part of the table, but the ranking should be based on system indices.

For the Vegetation Management report:

1. Company Testimony

2. Executive Summary (if not covered in Testimony)

3. Scheduled Maintenance Trimming (Incl. SMT, Midcycle, Hot Spot, Cust Work, METT, ROW Maint. Mowing/Side Trim)
    a. Proposed budget (each category if applicable)
    b. Actual spent
    c. Town/Circuit Designation
    d. Proposed circuit miles per circuit
    e. Actual circuit miles per circuit
    f. ROW Designation (ROW Maint. Mowing/Side Trim)
    g. Voltage
    h. Proposed acreage per ROW designation
    i. Actual acreage per ROW designation
    j. Percent of the clearing costs attributable to distribution if the ROW is shared with transmission

4. Enhanced Tree Trimming
    a. Proposed budget
    b. Actual spent
    c. Town/Circuit Designation
    d. Proposed circuit miles per circuit
    e. Actual circuit miles per circuit
    f. Circuit Ranking (Tree SAIDI and SAIFI - could be two different rankings)

5. Hazard Tree (Enhanced Tree Removal ("ETR"))
    a. Proposed budget
    b. Actual spent
    c. Town/Circuit Designation
    d. Actual number of trees removed per circuit

6. Right-of-Way ("ROW") Clearing
    a. Proposed Budget
    b. Actual spent
    c. ROW Designation
    d. Voltage
    e. Proposed circuit feet per ROW designation
    f. Actual circuit feet per ROW designation
    g. ROW width per ROW designation
    h. Percent of the clearing costs attributable to distribution if the ROW is shared with transmission

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY
Step Adjustment 1 - Projects Anticipated to be Placed in Service in 2019
Excludes New Business Projects

Line	Project Category	Project Description
1	Annual Blanket Project	DA9R: Non-Roadway Lighting PSNH
2	Annual Blanket Project	DG9R:Distributed Generation Field Design and Construction Reimbursable
3	Annual Blanket Project	DH9R: Line Relocations PSNH
4	Annual Blanket Project	DK9R: Maintain Voltage PSNH
5	Annual Blanket Project	DQ9R: System Repairs/Obsolescence PSNH
6	Annual Blanket Project	DR9R:Reliability Improvements PSNH
7	Annual Blanket Project	DT7P:Purchase Transformers and Regulators
8	Annual Blanket Project	HPS9R/D79R:Roadway Lighting PSNH
9	Annual Blanket Project	INS9R:Insurance Claims PSNH
10	Annual Program Project	6DCIP:NH Avigilon Intrusion Detection
11	Annual Program Project	A04S34:Direct Buried Cable Replacement
12	Annual Program Project	A07X45:Reject Pole Replacement
13	Annual Program Project	A07X98:NESC Capital Repairs
14	Annual Program Project	A08X45:Replace Steel Towers
15	Annual Program Project	A09S12:Replace Failed Cable - Post Tested
16	Annual Program Project	A10X04:Direct Buried Cable Injection
17	Annual Program Project	A12X01:Substation Battery Replacement
18	Annual Program Project	A12X02:Substation Ground Grid Upgrades
19	Annual Program Project	C01SPA01:Joint Poles Purchase & Sale
20	Annual Program Project	C03CTV:Cable TV Project Annual Program
21	Annual Program Project	C03DOT:NHDOT Project Annual Program
22	Annual Program Project	C03TEL:Telephone Projects Annual Program
23	Annual Program Project	CO1PCB:PCB Transformer Changeout Annual Program
24	Annual Program Project	CO1:New Business Specifics Unknown
25	Annual Program Project	DL9R:Distribution Line ROW Annual Program
26	Annual Program Project	DS9RD:Distribution Substation Maintenance Annual Program
27	Annual Program Project	DS9RE:ROW Replace Failed Equipment
28	Annual Program Project	DS9RS:Substation Annual-Substation Engineering group
29	Annual Program Project	DSPP8001:Distributed Generation Engineering Design and Construction
30	Annual Program Project	GF9R:Misc office equipment
31	Annual Program Project	GM9R:Tools/equipment - S/S Operations group
32	Annual Program Project	GT9R:Tools/equipment - Troubleshooter group
33	Annual Program Project	GX9R:Tools/equipment - Field Operations group
34	Annual Program Project	IT6DWANA:Telecom WAN Annual - PSNH
35	Annual Program Project	MINOR9R: Minor Storms Capital PSNH
36	Annual Program Project	NESCRC:NESC Patrol/Repair O&M Expense
37	Annual Program Project	NHLC03:NH Line Contractors
38	Annual Program Project	NT006:General Expense
39	Annual Program Project	PW9R:Private Work
40	Annual Program Project	ROWLR:ROW Relocations - Reimbursable

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY
Step Adjustment 1 - Projects Anticipated to be Placed in Service in 2019
Excludes New Business Projects

Line	Project Category	Project Description
41	Annual Program Project	STORMCAP:NH Storm Capitalization
42	Annual Program Project	UB3CAD:Porcelain Changeout
43	Annual Program Project	VEHICLES:NH Vehicle Purchases Distribution
44	Specific Project	18707:2018 Facilities LOB Building & General Plant
45	Specific Project	18726:ML 2018 PSNH LOB - General Plant
46	Specific Project	18734:Garage Addition
47	Specific Project	18740:Cafe Renovations
48	Specific Project	19707:2019 PSNHD Facilities LOB projects under $500k
49	Specific Project	19726:ML PSNH-D 2019 LOB - General Plant
50	Specific Project	19757:Bow Mobile Substation Garage Bay
51	Specific Project	A08W49:Keene Downtown UG Replacement Project
52	Specific Project	A09N05:Kingston S/S - Add Breakser Position
53	Specific Project	A12N01A:Berlin 4KV System Reconfiguration
54	Specific Project	A12W05:Replace Laconia Underground Switchgear 70W
55	Specific Project	A13S01:Rimmon S/S Add 2nd 115-34.5KV 44.8M
56	Specific Project	A13X04:Hazard Tree Removal
57	Specific Project	A14N10:Somersworth 34.5 KV OCB Replacement
58	Specific Project	A14N21:Berlin Eastside 34.5KV Line Breaker
59	Specific Project	A14S08:Garvins S/S Rebuild
60	Specific Project	A14W02:Daniel S/S (Webster)-34.5KV S/S Upgrade
61	Specific Project	A15C02A:388 Line Overload Solution Remote E
62	Specific Project	A15CDA:Central Region 2015 Distribution Automation Program
63	Specific Project	A15EDA:Eastern Region 2015 Distribution Automation Program
64	Specific Project	A15NDA:Northern Region 2015 Distribution Automation Program
65	Specific Project	A15SDA:Southern Region 2015 Distribution Automation Program
66	Specific Project	A15X01:Circuit Switcher TB31 Mobile
67	Specific Project	A16C02:12H4 West Side Conversion
68	Specific Project	A16C05:Valley St Area Solution
69	Specific Project	A16C09:Blaine St SS add 34.5-12kV 10MVA tr
70	Specific Project	A16C10:Jackman S/S - Replace Obsolete Equipment
71	Specific Project	A16E06:West Rye S/S Re-build
72	Specific Project	A16N02:Second transformer at Lost Nation S/S
73	Specific Project	A16X01:ESCC Control of Generation
74	Specific Project	A16X02:Circuit Tie 3271x2/311x1
75	Specific Project	A16X04:CAIDI Improvement
76	Specific Project	A16X05:NH Energy Park: audio visual equipment
77	Specific Project	A16X06:NH SOC/ESCC Backup
78	Specific Project	A16X08:1250 Hooksett Rd - AV Project
79	Specific Project	A17C04:Greggs S/S Removal
80	Specific Project	A17C13:Blaine St S/S Line Work
81	Specific Project	A17C17:Circuit Tie 3115X12 to 3615X1

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY
Step Adjustment 1 - Projects Anticipated to be Placed in Service in 2019
Excludes New Business Projects

Line	Project Category	Project Description
82	Specific Project	A17C21:Pine Hill S/S PLC Auto Scheme Replacement
83	Specific Project	A17C26:328 Line Reconductor
84	Specific Project	A17E01:Rye Area 4KV Study
85	Specific Project	A17E09:Rochester 4KV Conversion
86	Specific Project	A17E20:Ocean Rd S/S 34.5KV OCB Replacement
87	Specific Project	A17N02:Messer St - Replace TB70
88	Specific Project	A17N22:Beebe River S/S Cap Switcher Replacement
89	Specific Project	A17N24:Laconia S/S 24 VDC Control System & Relay
90	Specific Project	A17VRP:G&W Viper Warranty Replacement
91	Specific Project	A17W19:North Rd S/S Equipment Replacement
92	Specific Project	A17W23:Monadnock S/S Cap Switcher Replacement
93	Specific Project	A17X01:Mobile 115-34.5KV Substation
94	Specific Project	A18C21:Manchester Airport Duct Relocation
95	Specific Project	A18DA:Distribution Automation - Pole Top
96	Specific Project	A18E12:Circuit Ties 3172X1 - 3112X3
97	Specific Project	A18E16:West Rd Overloaded Steps
98	Specific Project	A18E23:Rochester Comcast Make Ready
99	Specific Project	A18N27:Laconia S/S Replace LTC Controls
100	Specific Project	A18VRP:Viper Replacement Project-Betterment
101	Specific Project	A18W10:55H1 Peterborough URD
102	Specific Project	A18W11:316X1 Circuit Tie Eastman Development
103	Specific Project	A18W13:Route 9 Roxbury-Sullivan 10439
104	Specific Project	A18W15:316 Line Rebuild
105	Specific Project	A18W22:Peterborough Roadway and Bridge Project
106	Specific Project	A18X01:Direct Buried Cable Replacement
107	Specific Project	A18X08:S Milford Relay Replacement
108	Specific Project	A18X20:CAIDI Improvement
109	Specific Project	A18XDA:Distribution Automation - Substation
110	Specific Project	A19C05:Reconductor Copper St Anselm Drive
111	Specific Project	A19C25:Reconductor Bedford Road, 360X7
112	Specific Project	A19DA:Distribution Automation - Pole Top
113	Specific Project	A19E11:Circuit Ties-Wakefield 362 to 3157
114	Specific Project	A19E26:Convert Four Rod Road in Rochester
115	Specific Project	A19E39:Replace Failed Cabble Spring Rd Rye
116	Specific Project	A19LS:Distribution Automation - Line Sensors
117	Specific Project	A19N09:Relocate 1W1 Main Line onto Route 3
118	Specific Project	A19N50:346X1 Defective SPCA Replacement
119	Specific Project	A19S08:Relocate 3168X Bridge St S/S
120	Specific Project	A19S27:Relocate 314 Line around Heron Pond
121	Specific Project	A19S46:South Ave Derry Step Overload
122	Specific Project	A19W03:Replace Open Wire with Spacer Cable Route 63

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY
Step Adjustment 1 - Projects Anticipated to be Placed in Service in 2019
Excludes New Business Projects

Line	Project Category	Project Description
123	Specific Project	A19W10: Relocate Feed to Hinsdale Wastewater
124	Specific Project	A19X20:Replace Lattice Steel Towers
125	Specific Project	A19X221:Animal Protection at Thornton S/S
126	Specific Project	A19X32:NH Lateral Initiative
127	Specific Project	A19X64:S/S Security Upgrades CIP5 NH
128	Specific Project	C18ETT:NH ETT 2018
129	Specific Project	C18HAZ:Hazard Tree Removal
130	Specific Project	C18ROW:NH Full Width ROW Clearing
131	Specific Project	D1249A:Webster S/S Expansion/Cap Bank Sared Assets-CE
132	Specific Project	D1276A:Distribution Design for F107 Project
133	Specific Project	D1338A:Distribution Design L176 Line Replacement
134	Specific Project	DPMNHAMP:UCONN Damage Prediction Model Expansion
135	Specific Project	IASC1904:1580 CIP PSP Expansion
136	Specific Project	IT18450:2018 Win10 PC Lifecycle - PSNH
137	Specific Project	MS17N006:NH 2017 Storm Event N: Oct 29
138	Specific Project	NHMTR17:NH Capital Meter Annual Project
139	Specific Project	NHMTR18:NH Annual Meter Project for 2018
140	Specific Project	NHMTR19:NH Annual Meter Project for 2019
141	Specific Project	R15CDA:REP3 - 2015-2016 Central Region Distribution Automation
142	Specific Project	R15CTC:Circuit Tie Construction
143	Specific Project	R15DBI:Direct Buried Cable Injection
144	Specific Project	R15DBR:REP3 Direct Buried Cable Replacement
145	Specific Project	R15EDA:REP 3 2015-2016 Eastern Region Distribution Automation
146	Specific Project	R15HLDR:Hit List Reliability Enhancements
147	Specific Project	R15HLR:Heather-Lite Replacement
148	Specific Project	R15NDA:REP3 - 2015-2016 Northern Region Distribution Automation
149	Specific Project	R15NESC:NESC Capital Repairs
150	Specific Project	R15POR:Porcelain Change-out
151	Specific Project	R15RPR:Reject Pole Replacement
152	Specific Project	R15RWM:ROW System Hardening
153	Specific Project	R15SDA:REP3 - 2015-2017 Southern Region Distribution Automation
154	Specific Project	R15SSAI:4 & 12 kV Substations
155	Specific Project	R15TDA:Telecom Expansion to Support Distribution Automation
156	Specific Project	R15WDA:REP3 - 2015-2016 Western Region Distribution Automation
157	Specific Project	R16LS:2016 Line Sensor Project
158	Specific Project	R17CTC:REP 4 Circuit Ties
159	Specific Project	R17DA:REP 4 Pole Top Distribution Automation
160	Specific Project	R17HLDR:REP 4 Circuit Reliability Improvements
161	Specific Project	R17RWH:REP 4 ROW System Hardening
162	Specific Project	R18CTC01:W185 - 4W1 Circuit Tie
163	Specific Project	R18CTC02:3178X Circuit Tie Hinsdale

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY
Step Adjustment 1 - Projects Anticipated to be Placed in Service in 2019
Excludes New Business Projects

Line	Project Category	Project Description
164	Specific Project	R18ETT:NH REP ETT
165	Specific Project	R18HAZ:NH Hazard Tree Removal
166	Specific Project	STRM0617N:NH STORM CAP: Oct 29, 2017 event
167	Specific Project	STRM0618C:NH STORM CAP: Mar 7-8, 2018 event
168	Specific Project	STRM0618D:NH STORM CAP: Apr 4-5, 2018 event
169	Specific Project	UB1412:2014 Distribution Automation Deployment
170	Specific Project	UB1501:Replace Defective Viper Reclosers
171	Specific Project	UB1502:399 Line Relocation Pointe Place

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY
Step Adjustment 2 - Projects Anticipated to be Placed in Service in 2020
Excludes New Business Projects

Line	Project Category	Project Description
1	Annual Blanket Project	DA9R: Non-Roadway Lighting PSNH
2	Annual Blanket Project	DG9R:Distributed Generation Field Design and Construction Reimbursable
3	Annual Blanket Project	DH9R: Line Relocations PSNH
4	Annual Blanket Project	DK9R: Maintain Voltage PSNH
5	Annual Blanket Project	DQ9R: System Repairs/Obsolescence PSNH
6	Annual Blanket Project	DR9R:Reliability Improvements PSNH
7	Annual Blanket Project	DT7P:Purchase Transformers and Regulators
8	Annual Blanket Project	HPS9R/D79R:Roadway Lighting PSNH
9	Annual Blanket Project	INS9R:Insurance Claims PSNH
10	Annual Program Project	6DCIP:NH Avigilon Intrusion Detection
11	Annual Program Project	A04S34:Direct Buried Cable Replacement
12	Annual Program Project	A07X45:Reject Pole Replacement
13	Annual Program Project	A07X98:NESC Capital Repairs
14	Annual Program Project	A08X45:Replace Steel Towers
15	Annual Program Project	A09S12:Replace Failed Cable - Post Tested
16	Annual Program Project	A10X04:Direct Buried Cable Injection
17	Annual Program Project	A12X01:Substation Battery Replacement
18	Annual Program Project	A12X02:Substation Ground Grid Upgrades
19	Annual Program Project	C01SPA01:Joint Poles Purchase & Sale
20	Annual Program Project	C03CTV:Cable TV Project Annual Program
21	Annual Program Project	C03DOT:NHDOT Project Annual Program
22	Annual Program Project	C03TEL:Telephone Projects Annual Program
23	Annual Program Project	CO1PCB:PCB Transformer Changeout Annual Program
24	Annual Program Project	DL9R:Distribution Line ROW Annual Program
25	Annual Program Project	DS9RD:Distribution Substation Maintenance Annual Program
26	Annual Program Project	DS9RE:ROW Replace Failed Equipment
27	Annual Program Project	DS9RS:Substation Annual-Substation Engineering group
28	Annual Program Project	DSPP8001:Distributed Generation Engineering Design and Construction
29	Annual Program Project	E03CTV:Expense Portion of CATV Projects
30	Annual Program Project	GE9R:Tools and Equipment - Engineering
31	Annual Program Project	GF9R:Misc office equipment
32	Annual Program Project	GM9R:Tools/equipment - S/S Operations group
33	Annual Program Project	GT9R:Tools/equipment - Troubleshooter group
34	Annual Program Project	GX9R:Tools/equipment - Field Operations group
35	Annual Program Project	IT6DWANA:Telecom WAN Annual - PSNH
36	Annual Program Project	MINOR9R: Minor Storms Capital PSNH
37	Annual Program Project	NHLC03:NH Line Contractors
38	Annual Program Project	NHTOOLS:NH-Tools/equipment-Transportation group
39	Annual Program Project	ROWLR:ROW Relocations - Reimbursable
40	Annual Program Project	STORMCAP:NH Storm Capitalization
41	Annual Program Project	UB3CAD:Porcelain Changeout
42	Annual Program Project	VEHICLES:NH Vehicle Purchases Distribution
43	Specific Project	18707:2018 Facilities LOB Building & General Plant

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY
Step Adjustment 2 - Projects Anticipated to be Placed in Service in 2020
Excludes New Business Projects

Line	Project Category	Project Description
44	Specific Project	18726:ML 2018 PSNH LOB - General Plant
45	Specific Project	19707:2019 PSNHD Facilities LOB projects under $500k
46	Specific Project	19720:Nashua Renovation
47	Specific Project	19726:ML PSNH-D 2019 LOB - General Plant
48	Specific Project	19781:Front Office Renovation
49	Specific Project	20707:PSNH-D Fac 2020 LOB
50	Specific Project	20715:PNSH-D ML 2020 LOB
51	Specific Project	20739:Berlin NH Yard Paving
52	Specific Project	20749:1250 Hooksett Rd. Parking Lot
53	Specific Project	20755:Bow Mobile Substation Expansion
54	Specific Project	20CGVE06:2020 Customer Group Vehicles for NH
55	Specific Project	A08N10:Portsmouth S/S - Add Transformer
56	Specific Project	A08W49:Keene Downtown UG Replacement Project
57	Specific Project	A14N08:Gorham S/S-Generation Divestiture
58	Specific Project	A14N21:Berlin Eastside 34.5KV Line Breaker
59	Specific Project	A14W01:Emerald Street S/S
60	Specific Project	A14W02:Daniel S/S (Webster)-34.5KV S/S Upgrade
61	Specific Project	A14W18:North Keene S/S New Distribution Circuit
62	Specific Project	A15CDA:Central Region 2015 Distribution Automation Program
63	Specific Project	A15EDA:Eastern Region 2015 Distribution Automation Program
64	Specific Project	A15NDA:Northern Region 2015 Distribution Automation Program
65	Specific Project	A15SDA:Southern Region 2015 Distribution Automation Program
66	Specific Project	A16C06:324 Line Rebuild at Industrial Ave
67	Specific Project	A16C08:Brook St S/S - 13TR1 Replacement
68	Specific Project	A16C09:Blaine St S/S add 34.5-12kV 10MVA transformer
69	Specific Project	A16C10:Jackman S/S - Replace Obsolete Equipment
70	Specific Project	A16N01:11W1 - Replace Submarine Cable
71	Specific Project	A16N02:Second transformer at Lost Nation S/S
72	Specific Project	A16S02:Reconductor Lines 3110, 353, 3445X
73	Specific Project	A16W01:Claremont Area Substation Upgrades
74	Specific Project	A16X01:ESCC Control of Generation
75	Specific Project	A16X04:CAIDI Improvement
76	Specific Project	A17C04:Greggs S/S Removal
77	Specific Project	A17C10:Brook St Replace G&W Switchgear
78	Specific Project	A17C12:3.74 Primary Voltage Conversion Navigator Rd
79	Specific Project	A17C13:Blaine St S/S Line Work
80	Specific Project	A17C17:Circuit Tie 3115X12 to 3615X1
81	Specific Project	A17C21:Pine Hill S/S PLC Auto Scheme Replacement
82	Specific Project	A17C26:328 Line Reconductor
83	Specific Project	A17C30:Pack Monadnock Rebuild Single-Phase Line
84	Specific Project	A17E01:Rye Area 4KV Study
85	Specific Project	A17E05:Twombley S/S Rebuild
86	Specific Project	A17E09:Rochester 4KV Conversion
87	Specific Project	A17E20:Ocean Rd S/S 34.5KV OCB Replacement

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY
Step Adjustment 2 - Projects Anticipated to be Placed in Service in 2020
Excludes New Business Projects

Line	Project Category	Project Description
88	Specific Project	A17N02:Messer St - Replace TB70
89	Specific Project	A17N18:Laconia S/S Equipment Replacement
90	Specific Project	A17N22:Beebe River S/S Cap Switcher Replacement
91	Specific Project	A17S03:Millyard S/S Replacement
92	Specific Project	A17VRP:G&W Viper Warranty Replacement
93	Specific Project	A17W19:North Rd S/S Equipment Replacement
94	Specific Project	A17W23:Monadnock S/S Cap Switcher Replacement
95	Specific Project	A18C02:Bedford S/S PLC Automation Scheme
96	Specific Project	A18C07:Eddy S/S Control House
97	Specific Project	A18DA:Distribution Automation - Pole Top
98	Specific Project	A18E04:Cocheco St Rebuild
99	Specific Project	A18E09:Replace 386 Relay at Rochester S/S
100	Specific Project	A18E12:Circuit Ties 3172X1 - 3112X3
101	Specific Project	A18E23:Rochester Comcast Make Ready
102	Specific Project	A18N03:White Lake S/S Rebuild
103	Specific Project	A18N05:Pemi S/S Upgrade
104	Specific Project	A18N27:Laconia S/S Replace LTC Controls
105	Specific Project	A18VRP:Viper Replacement Project-Betterment
106	Specific Project	A18W06:Monadnock S/S Replace Transformer TB40
107	Specific Project	A18W13:Route 9 Roxbury-Sullivan 10439
108	Specific Project	A18W17:Emerald St Line Work
109	Specific Project	A18W22:Peterborough Roadway and Bridge Project
110	Specific Project	A18X08:S Milford Relay Replacement
111	Specific Project	A18X18:ROW Hardening/Reconductoring
112	Specific Project	A18X26:Mobile Substation 46x34.5kV-12.47/7.2
113	Specific Project	A18X28:44 & 60 West Penn Telecom
114	Specific Project	A18XDA:Distribution Automation - Substation
115	Specific Project	A19C25:Reconductor Bedford Road, 360X7
116	Specific Project	A19C33:Animal Protection at Rimmon S/S
117	Specific Project	A19C54:Pettingill Switchgear Reconfiguration
118	Specific Project	A19DA:Distribution Automation - Pole Top
119	Specific Project	A19E07:Downtown Portsmouth UG System Improvements
120	Specific Project	A19E11:Circuit Ties-Wakefield 362 to 3157
121	Specific Project	A19E26:Convert Four Rod Road in Rochester
122	Specific Project	A19E41:Replace LTC Controls at Madbury S/S
123	Specific Project	A19E52:Dover Underground Backfeed Relocation
124	Specific Project	A19E63:Jackson Hill S/S Fence & Grounding Replacement
125	Specific Project	A19LS:Distribution Automation - Line Sensors
126	Specific Project	A19N09:Relocate 1W1 Main Line onto Route 3
127	Specific Project	A19N12:Circuit Ties - Laconia 310 to 345
128	Specific Project	A19N50:346X1 Defective SPCA Replacement
129	Specific Project	A19S06:Replace Conductor Route 13 Amherst
130	Specific Project	A19S08:Relocate 3168X Bridge St S/S
131	Specific Project	A19S27:Relocate 314 Line around Heron Pond

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY
Step Adjustment 2 - Projects Anticipated to be Placed in Service in 2020
Excludes New Business Projects

Line	Project Category	Project Description
132	Specific Project	A19S40:Amherst S/S - PLC Automation Replacement
133	Specific Project	A19S46:South Ave Derry Step Overload
134	Specific Project	A19W03:Replace Open Wire with Spacer Cable Route 63
135	Specific Project	A19W10: Relocate Feed to Hinsdale Wastewater
136	Specific Project	A19W55:Jackman S/S LTC Control Replacement
137	Specific Project	A19W56:317 Line Reconstruction
138	Specific Project	A19X01:Replace Degraded Manholes
139	Specific Project	A19X20:Replace Lattice Steel Towers
140	Specific Project	A19X22:Install Animal Protection
141	Specific Project	A19X220:Animal Protection at Tasker Farm S/S
142	Specific Project	A19X222:Animal Protection at Amherst S/S
143	Specific Project	A19X223:Animal Protection at Valley St S/S
144	Specific Project	A19X24:NESC Capital Repairs
145	Specific Project	A19X32:NH Lateral Initiative
146	Specific Project	A19X351:Long Hill S/S 34.5kV Cap Bank Switch
147	Specific Project	A19X3601:Reeds Ferry S/S OCB Replacement
148	Specific Project	A19X58:Replace Lattice Steel Towers
149	Specific Project	A19X61:High Impedance Ground Fault Detection NH
150	Specific Project	A19X64:S/S Security Upgrades CIP5 NH
151	Specific Project	A19XDA:Distribution Automation - Substation
152	Specific Project	A20C16:Bouchard St Replace Cable and Switchgear
153	Specific Project	A20C23:335X1 Extend 19.9kV 1Phase to S. Bow Rd
154	Specific Project	A20C24:Install PM Step Transfer Route 13 Goffstown
155	Specific Project	A20C40:Manchester Network Cable Replacement
156	Specific Project	A20DA:Distribution Automation Pole Top
157	Specific Project	A20E04:North Dover Conversion
158	Specific Project	A20E25:Offload 63W1 at E. Northwood
159	Specific Project	A20LS:Distribution Automation Line Sensor
160	Specific Project	A20N01:Rebuild Berlin Underground System
161	Specific Project	A20N11:Voltage Conversion Lost Nation Rd
162	Specific Project	A20N15:43W1 (13W1) Construct Circuit Tie
163	Specific Project	A20N29:Laconia Comcast Non-Billable 2020
164	Specific Project	A20N30:Laconia Comcast Billable 2020
165	Specific Project	A20N31:Gilford Comcast Non-Billable 2020
166	Specific Project	A20N32:Gilford Comcast Billable 2020
167	Specific Project	A20S06:3159X Extend 3 Phase Boston Post Rd
168	Specific Project	A20S17:DB Cable Replacement Maple Hill Acres
169	Specific Project	A20S19:South Milford S/S
170	Specific Project	A20S22:Range Rd Windham Conversion
171	Specific Project	A20W07:Mason Rd Relocate 1500' Main Line to Roadside
172	Specific Project	A20W08:3155X6 Feed from the 3155X9
173	Specific Project	A20W09:Rte 9 Relocate 2800' Main Line to Roadside
174	Specific Project	A20W13:3410 and 315 Circuit Tie
175	Specific Project	A20W14:24X1 and 313X1 Circuit Tie

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY
Step Adjustment 2 - Projects Anticipated to be Placed in Service in 2020
Excludes New Business Projects

Line	Project Category	Project Description
176	Specific Project	A20W33:Pack Monadnock Summit Solution
177	Specific Project	A20W34:Byrd Ave S/S Upgrades
178	Specific Project	A20W35:Spring Street S/S Upgrades
179	Specific Project	A20X21:NH Distribution Management System
180	Specific Project	A20X220:Animal Protection at Bedford S/S
181	Specific Project	A20X221:Animal Protection at Mammoth S/S
182	Specific Project	A20X222:Animal Protection at Weare S/S
183	Specific Project	A20X223:Animal Protection at Timber Swamp S/S
184	Specific Project	A20X26:Spare 345-34.5kV Transformer
185	Specific Project	A20X38:2020 Circuit Patrol Repairs
186	Specific Project	C18ETT:NH ETT 2018
187	Specific Project	D1276A:Distribution Design for F107 Project
188	Specific Project	D1328AH:Distribution Design P134 Line
189	Specific Project	D1328I:Distribution Design Y138 Line
190	Specific Project	D1382A:Rochester S/S Relays
191	Specific Project	IASC2006:PSNH Security Capital Project 2020
192	Specific Project	IT19433:Lifecycle PC Replacements-237
193	Specific Project	IT20437:2020 Modern Desktop - PSNH-Distribution
194	Specific Project	NHEDVH20:NH Distribution Vehicle Purchase
195	Specific Project	NHMTR18:NH Annual Meter Project for 2018
196	Specific Project	NHMTR19:NH Annual Meter Project for 2019
197	Specific Project	NHMTR20:NH Annual Meter Project for 2020
198	Specific Project	NHRMTR17:NH Remote Disconnect 2017-2018
199	Specific Project	NHTRN20:NH Training Annual Capital Project
200	Specific Project	R15CDA:REP3 - 2015-2016 Central Region Distribution Automation
201	Specific Project	R15DBR:REP3 Direct Buried Cable Replacement
202	Specific Project	R15NDA:REP3 - 2015-2016 Northern Region Distribution Automation
203	Specific Project	R15POR:Porcelain Change-out
204	Specific Project	R15RPR:Reject Pole Replacement
205	Specific Project	R15RWM:ROW System Hardening
206	Specific Project	R15SDA:REP3 - 2015-2017 Southern Region Distribution Automation
207	Specific Project	R15TDA:Telecom Expansion to Support Distribution Automation
208	Specific Project	R15WDA:REP3 - 2015-2016 Western Region Distribution Automation
209	Specific Project	R18CTC01:W185 - 4W1 Circuit Tie
210	Specific Project	R18CTC02:3178X Circuit Tie Hinsdale
211	Specific Project	STRM0617N:NH STORM CAP: Oct 29, 2017 event
212	Specific Project	TCORP1NH:Transport NW Refresh Phase 1 NH

DE 19-057 – APPENDIX 6

Fee Free Credit/Debit Card Payment

As noted in Section 12 of the Settlement, PSNH shall implement a fee free credit or debit card option for residential customers to use to make non-recurring credit or debit card payments without incurring a transaction fee. Information on the program, its costs, and presumed adoption rates is included in this appendix.

As described in the Company's Testimony of Penelope McLean Conner May 28, 2019 at Bates Pages 759-772 the Company sought to offer fee free credit/debit cards to residential customers. For purposes of settlement, the Settling Parties agreed that a fee free program will be implemented with the following criteria. The program will be implemented consistent with Ms. Conner's testimony, and limited to residential customers for one-time payments. Automatic recurring payments will not be supported, meaning that customers will be required to enter their credit or debit card payment information for each payment transaction. The Company will report information on the migration of customers to this option to inform potential future decisions on whether to continue, alter, or eliminate the fee free program.

As part of this submission, the Company herein provides updated fee free credit card utilization rates as a percentage of total customer payments based on actual participation rates in the Company's affiliate's Connecticut residential fee free program and with input from peer utilities:

- Using information from Eversource's affiliate in Connecticut, the percent of payments made via credit card increased by 1.3% the year following removal of the fees. This review excluded the COVID pandemic period because it is not representative of normal customer behavior.

- Based on information provided by Unitil, which has offered a fee free option for over 10 years, Unitil reports a steady state percentage of total customer payments made via credit card compared to all payments of approximately 18%.

Based upon this information, the Company has updated the adoption assumptions for the program in New Hampshire, resulting in lower adoption assumptions and, therefore, lower cost estimates for the first four years of the program than those provided in the initial rate case filing. The updated yearly adoption rates as a percent of total payments are 5%, 6.3%, 7.6% and 8.9% for years 1 through 4, respectively. The updated net cost for the first four years is $2,081,987 or $520,497 per year on average as shown in the chart below. The Company's revenue requirement is revised from $706,764 per year as proposed in the initial filing to $375,000 to reflect the costs presumed for the first year of the program. Should the actual costs resulting from customers' adoption of the fee free option exceed the $375,000 allowed in rates in the first year, the Company shall increase the amount in rates to an amount reflecting the estimated cost, but not more than $520,500, effective February 1, 2022.

NH Net Cost Savings Calculation (Residential Only)				
Year	**Fee Free Penetration Rate %**	**Price**	**Total Offsetting Savings**	**Net Cost**
1	5.00%	$ 389,901	$ 15,443	$ 374,458
2	6.30%	$ 491,276	$ 19,458	$ 471,817
3	7.60%	$ 592,650	$ 23,474	$ 569,176
4	8.90%	$ 694,024	$ 27,489	$ 666,535
Total		**$ 2,167,851**	**$ 85,864**	**$ 2,081,987**

DE 19-057 – APPENDIX 7

New Start - Arrears Management Program

As stated in Section 13 of the Settlement, PSNH shall implement an arrears management program known as "New Start." New Start is an arrearage management program offered by PSNH that provides payment assistance for qualifying residential customers struggling with past due utility bills. A general description of the program's rules and requirements, and a list of the agreed upon reporting metrics, is set out in this Appendix as follows.

Program Rules

To be eligible for New Start in New Hampshire, each customer:

- Must be a residential customer with active service;
- Have an account balance that is greater than or equal to $150 and the $150 is at least 60 days overdue; and
- Has provided the utility with evidence of "financial hardship" through their current enrollment or their household's current enrollment in the Low Income Home Energy Assistance Program, the Electric Assistance Program, the Gas Residential Low Income Assistance Program, the Neighbor Helping Neighbor Program, their successor programs, or any other federal, state or local government program or government funded program of any social service agency which provides financial assistance or subsidy assistance for low income households based upon a written determination of household financial eligibility as outlined in Puc 1202.09.

Residential customers with a certified medical emergency must also qualify as financial hardship and meet the eligibility criteria as described above in order to participate in the New Start program. A medical emergency alone does not qualify.

New Start Reporting

Once established, PSNH will provide regular reporting on the activities of the New Start program. PSNH will base its reports on the below described metrics:

i. Number of customer accounts verified financial hardship.
   - The total number of customers who are verified financial hardship as of the end of a month.

ii. Number of customers enrolled in the program.
   - The total number of customers enrolled in the New Start program as of the end of a month.

iii. Number of customers who successfully completed the program.
   - The number of customers who have completed the program during the month.

iv. Number of customers dropped from the program.
   - The number of customers removed from the program for missed payments and all other reasons during the month.

v. Number of customers who re-enroll in the program after being dropped and length of time before re-enrollment.
   - The number of customers who have re-enrolled on New Start and the average number of months since being dropped from the program.

vi. Number of customers who newly enroll in the program after successful completion and length of time before new enrollment.
   - The number of customers who have enrolled in New Start after successfully completing the program within the last 3 years, and the average length of time between completion and new enrollment.

vii. Number of customers who remain on a budget plan after automatic enrollment upon completion and for how long.
   - The number of customers who remain on the budget for each of the following periods of time: 1-3 Months, 3-6 Months, 6-9 Months, 9-12 Months, 12-18 Months, 18-36 Months.

viii. Total dollar amount of arrearages forgiven.
   - The total amount of dollars forgiven by month.

ix. Average dollar amount per participating customer of arrearages forgiven.
- The average dollar amount of arrears forgiven for customers who received forgiveness during a month.

x. Comparison of disconnections for financial hardship customers before and after program start.
- The number of 2019 financial hardship residential customers disconnected and eligible for disconnection by month, and the number of financial hardship residential customers disconnected and eligible for disconnection after the program starts.

xi. Comparison of lead-lag before and after program start.
- The comparison of the number of days revenue outstanding for hardship customers not on New Start compared to those that are on New Start.

xii. Comparison of bills behind for hardship customers before and after program start.
- The average amount of delinquency in dollars and days aged in 2019 compared to months after the program starts.

xiii. Quantification of impact of program on field visits and customer service.
- The number of field visits per month, and customer satisfaction metrics.

xiv. Quantification of impact of program on reconnections.
- The number of credit reconnects and subsequent enrollment or re-enrollment on the New Start program.

xv. Quantification of impact of program on uncollectible.
- The 12-month rolling Net Write-Off as a Percent of Revenue lagged 6 months. This indicates the percentage of revenue is written off less any recoveries.

xvi. The dollars of bills for current service by month.
- The total budget amount billed to New Start customers during a month.

xvii. The dollars of actual receipts from customers by month.
- The total amount of payments made by New Start customers during a month.

xviii. The number of accounts receiving a bill by month.
- The number of accounts on the New Start program that were sent a bill during a month.

xix. The number of accounts making a payment by month.
- The number of accounts on the New Start program that made any amount of payment during a month.

xx. The number of accounts that are either one or two payments behind on the New Start Program.

xxi. The dollars of New Start budget arrears of customers that are either one or two payments behind on the program.

xxii. The average arrears of accounts with arrears (other than their New Start arrears) by month.

- The average New Start budget arrears for customers that are one or two payments behind on the program (xxi divided by xx).

xxiii. The number of accounts with a $0 balance by month.

- The number of accounts that are current on the New Start program, where the owed balance is less than or equal to the current bill.

DE 19-057 – APPENDIX 8

Outdoor Lighting

As noted in Section 14 of the Settlement, PSNH shall be creating a new rate ("EOL-2") to allow additional flexibility and options for municipalities to install advanced lights and lighting controls, and to allow municipalities to own and maintain the streetlights in their communities. Additionally, PSNH shall work with interested parties on final tariff language to implement this provision. Included below is a framework for the structure of that new rate offering which will form the basis for the final tariff language to be presented to the Commission.

	Current EOL Tariff	**New Tariff (EOL-2)**
Purchase of Lights	Customer purchases LED lights, pays for undepreciated value of existing lights at NBV.	Customer purchases lights from Company at undepreciated value of existing lights at NBV.
New Asset Treatment	Turned over to Company at $0 NBV.	Customer maintains ownership.
New installation?		
Installation of LED Lights	Company or Customer can install. Customer responsible for all installation costs.	Customer installs. Customer responsible for[1] all installation costs.
Contractor Approval Required	Yes	Yes
Maintenance Responsibility	Company	Customer – Fixture (OH) or Base/pole/head only (UG) (see Ownership Line of Demarcation)
Ownership Line of Demarcation	N/A – Company maintains ownership of all assets	Customer owns fixture[2] while Company owns bracket, service wire, etc. up to but excluding fixture (OH). [3]
Responsibility of Replacement of Asset due to Accident or Property Damage	Customer responsibility at $95 per fixture per visit plus cost of materials. Company would update with the rates in the new Tariff.	Propose to update to $189 for cost of removal and installation of each light (fixture). If customer only wants us to remove, then $90 per light.
Clear, ongoing Company responsibilities?	Customer pays cost of removal if replaced	Customer pays cost of removal if replaced

1 Potential fees for remove and/or replacement services
2 Clarify details; contrast with CT customer-owned lighting, where Eversource owns & maintains the secondaries & customer is responsible for the bracket (and fixture) & the secondary wire inside the bracket. Eversource connects our secondary to this wire which is the demarcation point.
3 Similarly, for UG service, Company facility ownership demarcation required (e.g., up to but excluding base)

PUBLIC SERVICE OF NEW HAMPSHIRE, DBA EVERSOURCE ENERGY
DOCKET NO. DE 19-057

SETTLEMENT APPENDIX 9
PROPOSED TARIFF CHANGES

NHPUC NO. 10 – ELECTRICITY DELIVERY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

DBA EVERSOURCE ENERGY

TARIFF FOR ELECTRIC DELIVERY SERVICE

in

Various towns and cities in New Hampshire,

served in whole or in part.

(For detailed description, see Service Area)

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

Page

DELIVERY SERVICE RATE SCHEDULES

ENERGY SERVICE RATE SCHEDULES

ENERGY EFFICIENCY PROGRAM

TERMS AND CONDITIONS FOR DELIVERY SERVICE

1. Service Area

The territory authorized to be served by this Company and to which this Tariff applies is as follows:

Albany#	Bridgewater#	Danbury#	Freedom#
Alexandria*	Bristol#	Danville**	Fremont#
Allenstown#	Brookfield#	Deerfield*	Gilford#
Alstead**	Brookline	Deering	Gilmanton
Alton**	Cambridge	Derry#	Gilsum
Amherst	Campton*	Dover	Goffstown
Andover**	Candia*	Dublin	Gorham
Antrim	Canterbury*	Dummer	Goshen*
Ashland**	Carroll	Dunbarton#	Grafton#
Atkinson*	Charlestown*	Durham#	Grantham#
Auburn#	Chatham	Easton*	Greenfield
Barnstead*	Chester*	Eaton#	Greenland
Barrington	Chesterfield	Effingham	Greenville
Bath#	Chichester*	Enfield**	Green's Grant
Bedford	Claremont#	Epping#	Hampstead#
Belmont#	Clarksville*	Epsom*	Hampton**
Bennington	Colebrook*	Errol	Hancock
Berlin	Columbia*	Exeter**	Hanover**
Bethlehem#	Concord**	Farmington#	Harrisville
Boscawen**	Conway*	Fitzwilliam	Haverhill*
Bow**	Cornish*	Francestown	Hebron#
Bradford	Croydon#	Franconia	Henniker
Brentwood*	Dalton	Franklin#	Hill**

\# Company serves over 90 percent of the customers in this municipality. (See Note)

* Company serves less than 90 percent but more than 10 percent of the customers in this municipality. (See Note)

** Company serves less than 10 percent of the customers in this municipality. (See Note)

Note: Limited areas of towns so identified above are as shown on the maps filed separately with the Commission and incorporated in this Tariff by reference.

Issued: October 9, 2020 Issued by: Joseph A. Purington

Effective: January 1, 2021 Title: President and Chief Operating Officer

Hillsborough
Hinsdale
Hollis
Hooksett
Hopkinton#
Hudson
Jaffrey
Jefferson
Keene
Laconia#
Lancaster
Landaff*
Lee*
Lempster**
Lincoln**
Lisbon#
Litchfield
Littleton**
Londonderry
Loudon
Lyman#
Lyme*
Lyndeboro
Madbury
Madison#
Manchester
Marlboro
Marlow#
Martin's Location
Mason
Meredith**
Merrimack
Middleton
Milan
Millsfield
Milford
Milton
Mont Vernon
Nashua
Nelson
New Boston
New Castle
New Durham*
New Hampton*
New Ipswich
New London
Newbury
Newfields
Newington
Newmarket
Newport#
North Hampton
Northfield*
Northumberland
Northwood#
Nottingham*
Orange**
Orford*
Ossipee*
Pelham**
Pembroke#
Peterborough
Piermont*
Pinkham's Grant
Pittsburg#
Pittsfield#
Plainfield*
Plymouth**
Portsmouth
Randolph
Raymond*
Richmond
Rindge
Rochester
Rollinsford
Roxbury
Rye
Salisbury*
Sanbornton#
Sandown*
Sandwich*
Seabrook**
Sharon
Shelburne
Somersworth
Springfield*
Stark
Stewartstown*
Stoddard
Strafford
Stratford
Stratham**
Sugar Hill
Sullivan
Sunapee*
Surry#
Sutton#
Swanzey
Tamworth#
Temple
Thornton
Tilton
Tuftonboro*
Troy
Unity*
Wakefield#
Warner
Washington
Waterville**
Weare
Webster*
Wentworth's Location
Westmoreland
Whitefield
Wilmot**
Wilton
Winchester
Windham#
Windsor

\# Company serves over 90 percent of the customers in this municipality. (See Note)

* Company serves less than 90 percent but more than 10 percent of the customers in this municipality. (See Note)

** Company serves less than 10 percent of the customers in this municipality. (See Note)

Note: Limited areas of towns so identified above are as shown on the maps filed separately with the Commission and incorporated in this Tariff by reference.

Issued: October 9, 2020 — Issued by: Joseph A. Purington

Effective: January 1, 2021 — Title: President and Chief Operating Officer

2. Definitions

The following words and terms shall be understood to have the following meanings when used in this Tariff, including in any agreements entered into under this Tariff:

Application: A request by a Customer for Delivery Service pursuant to the provisions of this Tariff.

Commission: The State of New Hampshire Public Utilities Commission.

Company: Public Service Company of New Hampshire dba Eversource Energy.

Customer: Any person, firm, corporation, cooperative marketing association, utility or government unit or sub-division of a municipality or of the state or nation supplied with Delivery Service by the Company. Each Delivery Service account shall be considered a separate and distinct Customer.

Customer Choice Date: May 1, 2001.

Default: A Supplier's or its Market Participant member's failure or inability to maintain good standing with ISO-NE pursuant to the terms of ISO-NE Inc. Transmission, Markets, and Service Tariff, including a Financial Assurance Default, or the Supplier's or Market Participant member's failure or inability to maintain good standing with the requirements of the Commission.

Default Energy Service ("Default Service"): Electric energy, capacity and ancillary services supplied to a Customer by the Company. Service shall be supplied during periods in which a Customer is not receiving Self-Supply Service or Supplier Service. Default Service shall be provided in accordance with Default Energy Service Rate DE and shall be provided in conjunction with the applicable Delivery Service Rate Schedule.

Delivery Service: The delivery of electric power by the Company to a Customer under this Tariff.

Electronic Enrollment: A request submitted electronically to the Company by a Supplier for the initiation of Supplier Service to a Customer.

Energy Service Provider ("Supplier"): Any entity registered with the Commission and authorized by the Commission to supply electricity to retail users of electricity in the state of New Hampshire.

Eversource Energy System Companies: The operating companies of Eversource Energy other than Public Service Company of New Hampshire.

FERC: The Federal Energy Regulatory Commission.

Financial Assurance Default: A Supplier's or its Market Participant member's failure or inability to meet financial requirements as determined by ISO-NE.

Force Majeure: Any cause beyond the reasonable control of, and without the fault or negligence of, the Party claiming Force Majeure. It shall include, without limitation, sabotage, strikes or other labor difficulties, soil conditions, riots or civil disturbance, acts of God, acts of public enemy, drought, earthquake, flood, explosion, fire, lightning, landslide, sun storms or similarly cataclysmic occurrence, or appropriation or diversion of electricity by sale or order of any governmental authority having jurisdiction thereof. Economic hardship of either Party shall not constitute a Force Majeure under this Tariff.

Information and Requirements for Electric Supply: The booklet prepared by the Company to establish standardized rules and regulations for the installation of electric service connections within the Company's Service Area.

ISO-NE: The Independent System Operator of New England, the NEPOOL operating center that centrally dispatches the electric generating and transmission facilities owned or controlled by NEPOOL participants to achieve the objectives of the NEPOOL Agreement.

ISO-NE Rules: The Restated NEPOOL Agreement, ISO Tariff, ISO Manual and Participant's Agreement or by ISO-NE.

Local Network: The transmission and distribution facilities which are owned, leased and maintained by the Company, which are located in the states of New Hampshire and Maine and that are used to provide Delivery Service under this Tariff. The Local Network does not include any capacity or transmission or distribution facilities owned, leased or supported by the Eversource Energy System Companies.

Market Participant: An entity that has registered with ISO-NE to participate in New England's suite of wholesale electricity markets. They may produce, buy, sell, or transport wholesale electricity in the region.

Metering Domain: Connection points created within the ISO-NE settlement power system model that facilitate the calculation of the unmetered load asset value to ensure all generation and load is accounted for in the New England control area.

NEPOOL: The New England Power Pool.

Parties or Party: The Company and/or one or more Customers under this Tariff.

Payment Agent: Any third-party authorized by a Customer to receive and pay the bills rendered by the Company for service under this Tariff.

PTF Facilities: All pool transmission facilities included in the NEPOOL Open Access Transmission Tariff on file with the FERC.

Rate Schedule: The Rate Schedules included as part of this Tariff.

Restated NEPOOL Agreement ("NEPOOL Agreement"): An agreement between the NEPOOL participants dated September 1, 1971 and restated December 31, 1996, as amended from time to time.

Self-Supply Service: Electric energy and capacity purchased by a Customer directly from the Independent System Operator of New England or the New England Power Pool.

Settlement Agreement: The 2015 Public Service Company of New Hampshire Restructuring and Rate Stabilization Agreement as approved by the Commission in Order No. 25,920.

Supplier-Rendered Energy Service ("Supplier Service"): The sale of energy and capacity including ancillary services to a Customer by a Supplier.

Suspension or Suspended: An action taken by ISO-NE to remove a Supplier, or its Market Participant member, from active Market Participant status.

Tariff: This Delivery Service Tariff and all Rate Schedules, appendices and exhibits to such Tariff.

3. General

The Company undertakes to render dependable Delivery Service in accordance with this Tariff, of which these Terms and Conditions are a part, as on file from time to time with the Commission and legally in effect; such undertaking being subject to the applicable rules and regulations of the Commission and to the Company's "Information and Requirements for Electric Supply".

Although the Company will endeavor to make the service rendered as continuous and uninterrupted as it reasonably can, Delivery Service is subject to variations in its characteristics and/or interruptions to its continuity. Therefore, the characteristics of the Delivery Service may be varied and/or such service to any Customer or Customers may be interrupted, curtailed, or suspended in the following described circumstances; the obligations of the Company to render service under this Tariff are subject to such variance, interruption, curtailment, or suspension:

(a) When necessary to prevent injury to persons or damage to property.

(b) When necessary to permit the Company to make repairs to or changes and improvements in a part or parts of the Company's electrical facilities; such action to be taken upon reasonable notice to the Customers to be affected, if practicable, or without any notice in an emergency when such notification would be impracticable or would prolong a dangerous situation.

(c) When conditions in a part or parts of the interconnected generation-transmission system of which the Company's facilities are a part make it appear necessary for the common good.

(d) When such variance, including a reversal of supply, or such interruption, curtailment or suspension is a result of Force Majeure as defined in this Tariff and any cause except willful default or neglect on the Company's part.

The Company shall not be responsible for any loss, cost, damage or expense to persons and/or property resulting therefrom.

The Company does not undertake to regulate the voltage or frequency of its service more closely than is standard commercial practice or required by the rules of the Commission. If the Customer requires regulation of voltage or frequency that is more refined, the Customer shall furnish, install, maintain and operate the necessary apparatus at the Customer's expense.

4. Availability

Delivery Service shall be available to a Customer who has made an Application and has satisfied all of the requirements of this Tariff. Delivery Service shall be available solely for the delivery of electricity from a Supplier to a Customer or for the delivery of Default Service or Self-Supply Service to a Customer.

In the event that a conflict arises between this Tariff and the Terms and Conditions specifically related to transmission service under the ISO-NE Transmission, Markets, and Services Tariff ("ISO-NE Tariff"), including Schedule 21-ES, or successor thereto, then such ISO-NE Tariff will apply.

In the event a conflict arises between this Tariff and the Settlement Agreement, then the Settlement Agreement will take precedence over this Tariff.

In the event that a Customer is not receiving Self-Supply Service and is not receiving Supplier Service from a Supplier for any reason, the Company will arrange Default Service provided the Customer has satisfied all the requirements for service under this Tariff.

5. Application, Contract and Commencement of Service

Application by the Customer for Delivery Service may be made to the Company at any time. Whether or not an Application for service is made by the Customer and accepted by the Company, the rendering of the service by the Company and its use by the Customer shall be deemed a contract between the parties and subject to all provisions of the Tariff, as in effect from time to time, applicable to the service.

Except as otherwise specifically provided for under a rate, all rates are predicated on a period of service at one location of not less than twelve (12) consecutive months with monthly billing and monthly payment. The rendering of bills to Customers under this Tariff shall be performed exclusively by the Company.

6. Selection of Supplier or Self-Supply Service by a Customer

Any Customer requesting or receiving Delivery Service under this Tariff is responsible for selecting or changing a Supplier or selecting Self-Supply Service. The Company shall process a change in or initiation of Supplier Service or Self-Supply Service within two business days of receiving a valid Electronic Enrollment from a Supplier or notice from the Customer in the case of Self-Supply Service. The Supplier or the Customer in the case of Self-Supply Service must satisfy all the applicable requirements of this Tariff and the Commission's rules prior to the commencement of Supplier Service or Self-Supply Service. The date of change in, or initiation of, Supplier Service or Self-Supply Service shall commence upon the next meter reading date for the Customer provided the Company receives and successfully processes the Electronic Enrollment from a Supplier or notice from the Customer in the case of Self-Supply Service at least two business days prior to the regularly scheduled meter reading cycle date for the Customer.

The Company shall accept no more than one Supplier for a Customer during any particular monthly billing cycle.

For a new service location for which a Customer requests Delivery Service, the Company must receive an Electronic Enrollment from a Supplier to enable the rendering of Supplier Service in conjunction with Delivery Service or notice from the Customer to enable the rendering of Self-Supply Service in conjunction with Delivery Service. If an Electronic Enrollment has not been received by the Company from a Supplier for any reason or notice has not been received from the Customer to enable the rendering of Self-Supply Service, energy and capacity shall be provided under Default Energy Service.

If an Electronic Enrollment fails to meet the requirements of this Tariff, the Company shall, within one business day of receipt of the Electronic Enrollment, notify the Supplier requesting service of the reasons for such failure.

The Customer or its designee shall ensure that all information provided to the Company for Delivery Service is accurate and shall provide the Company with prompt notification of any changes thereto. The Customer's Supplier shall also ensure that all information contained in the Supplier's Electronic Enrollment is accurate and shall provide the Company with prompt notification of any changes thereto.

7. Termination of Supplier Service or Self-Supply Service

To terminate Supplier Service from a particular Supplier, a Customer may either have the Supplier of record send to the Company a "Supplier Drops Customer" transaction, in accordance with the Terms and Conditions for Energy Service Providers section of this Tariff, or request Supplier Service from an alternative Supplier. Supplier Service from the Supplier of record shall terminate on the next meter read date provided the Company has received either a valid "Supplier Drops Customer" notice from the Supplier of record or a valid Electronic Enrollment from a new Supplier at least two business days prior to the regularly scheduled meter read date.

To terminate Self-Supply Service, a Customer may either provide notice to the Company or request Supplier Service from a Supplier. Self-Supply Service shall terminate on the next meter read date provided the Company has received notice from the Customer or has received a valid Electronic Enrollment from a Supplier at least two business days prior to the regularly scheduled meter read date.

8. Unauthorized Switching of Suppliers

The Company is not responsible for any loss or damage (direct, indirect or consequential) to any persons resulting from the Company's processing of an unauthorized Electronic Enrollment received from a Supplier.

9. Conditions of Delivery Service

Under the NEPOOL Agreement, the day-to-day operation of the generation and transmission systems of NEPOOL Participants, including the Company, is subject to ISO-NE dispatch and control. It is understood that occasions may arise where ISO-NE imposes limitations on service rendered under this Tariff in order to reliably operate the regional bulk power system in accordance with ISO-NE Operating Procedures. The Company shall not be liable for any actions taken by ISO-NE in the performance of the Company's duties under the NEPOOL Agreement and related operating guidelines and procedures.

10. Deposits, Payments, Refusal or Discontinuance of Service

Until a Customer has established satisfactory credit relations or when unsatisfactory credit relations exist, the Company may require security in the form of a cash deposit or an irrevocable written guarantee of a responsible third party. Cash deposits should not be less than $10.00 nor more than the estimated bill for Delivery Service and Default Service for a period of two (2) high use months. The highest use month will not be used in determining the amount of deposit.

Interest on all deposits shall be accrued at a rate equal to the base rate on corporate loans at large United States money center commercial banks (the Prime Rate), from the date of deposit to the date of termination. The monthly simple interest rate on deposits shall be fixed on a quarterly basis for quarterly periods ending March, June, September and December of each calendar year and shall be established as one-twelfth (1/12) of the annual Prime Rate reported in The Wall Street Journal on the first business day of the month preceding the calendar quarter. If more than one Prime Rate is reported in The Wall Street Journal, the average of the reported rates shall be used. Deposits plus accrued simple interest thereon, less any amount due the Company, will be refunded to the Customer when satisfactory credit relations have been established, or upon termination of service. The refund of accrued interest amounts shall be made by the Company pursuant to the rules of the Commission. When a deposit or balance of a deposit cannot be refunded because the Company is unable to locate the Customer, no additional interest shall be accrued on the deposit.

Charges for service under rates in this Tariff are predicated upon monthly billing, which as far as practicable will be thirty (30) days apart and will be due upon presentation of bill. The Company may discontinue service for non-payment after a bill, or a portion thereof, becomes thirty (30) days overdue, or for other good cause, in accordance with applicable statutes and the rules and regulations of the Commission in effect at the time. Service to the Customer may be discontinued at the location where the Company furnished the service for which the overdue bill was rendered; or, if service is no longer being furnished to the Customer at that location, the Company may discontinue service at the current location, if the debt is uncontested and accrued within the past three years, subject to the Commission’s Rules and Regulations.

When service has been disconnected for nonpayment, the Company may make a reasonable charge for reconnection before service is restored.

Except as otherwise specifically provided in any agreement between the Company and the Customer, charges for service furnished under this Tariff shall continue until such time as the Company shall receive reasonable notice from the Customer of a desire to terminate the service. The date of termination shall be the date specified by the Customer but not sooner than four business days from the date the Customer notified the Company.

The Company may require an applicant, as a condition of new service, to enter into a reasonable repayment plan for an uncontested debt owed to the Company within the past three years. Uncontested debt shall include any amounts for services provided by the Company before the Customer Choice Date and/or any amounts for Delivery Service and any Default Service furnished to the applicant. The Company may require the applicant to pay a security deposit or provide a written third-party guarantee as allowed under the rules and regulations of the Commission.

11. Returned Payment Charge for Insufficient Funds

The Company shall assess a returned payment charge of $13 per returned payment to any Customer whose payment to the Company is dishonored by the Customer’s financial institution when presented by the Company. Receipt of a check or payment instrument that is subsequently dishonored by the Customer’s financial institution shall not be considered a valid payment.

12. Failure of Payment Agent to Remit Payment

A Customer who has elected to use a Payment Agent shall be treated in the same manner as other Customers in the Company’s application of the applicable statutes, rules and regulations of the Commission and the terms and conditions of this Tariff, notwithstanding any failure of the Payment Agent to remit payment to the Company or any failure of the Payment Agent to forward to the Customer any Company notices, bill inserts or other written correspondence. The Customer shall be solely responsible for all amounts due, including, but not limited to, any late payment charges.

13. Refusal to Serve

The Company reserves the right to refuse to supply Delivery Service to new Customers or to supply additional load to any existing Customer if it is unable to do so under a Rate Schedule or if it is unable to obtain the necessary equipment and facilities or capital required for the furnishing of such service. The Company may refuse to supply Delivery Service to load of unusual characteristics which might affect the cost or quality of service supplied to other Customers of the Company. The Company may require a Customer having such unusual load to install special regulating and protective equipment in accordance with the Company’s specifications as a condition of service.

The Company reserves the right to reject any Application for service if the amount or nature of the service applied for, or the distance of the premises to be served from an existing suitable distribution line, or the difficulty of access thereto, is such that the estimated income from the service applied for is insufficient, under any of the Company's applicable rates, to yield a reasonable return to the Company, unless such Application is accompanied by (a) a cash payment or (b) an undertaking satisfactory to the Company guaranteeing a stipulated revenue for a definite period of time, or both (a) and (b).

14. Maximum Demand

The "Maximum Demand" or "Customer's Load," which shall be stated in kilowatts or kilovolt-amperes as specified in the applicable Rate Schedule, is defined as the greatest rate of taking Delivery Service during a specified interval.

Where a Rate Schedule requires determination of maximum demand, it shall be determined by measurement or estimated as provided by the Rate Schedule or, where applicable, by the provisions of the following paragraph of this section. The Company shall not be obligated, for any reason, to use the demand values measured or estimated by any other entity in the determination of maximum demand.

When the nature of the Customer's load is of an intermittent, instantaneous or widely fluctuating character such as to render demand meter readings of doubtful value as compared to the actual capacity requirements, the demand may be determined on the basis of a time interval less than that specified, or on the basis of the minimum transformer capacity necessary to render the Delivery Service, or the minimum protective device rating necessary to permit continuous uninterrupted service. In all such instances, the Company will record the basis of demand determination.

15. Meters

The Company will provide each Customer with proper metering equipment subject to the ability of the Company to obtain the same.

The Company shall own and maintain the metering equipment necessary to measure Delivery Service under this Tariff. Each meter location shall be designated by the Company and the Company shall have priority over any other entity with respect to placement of Company-owned metering equipment.

Any Customer requesting non-standard metering equipment, the cost of which exceeds the cost of the metering equipment necessary for the rendering of Delivery Service under the applicable Rate Schedule, shall be responsible for the additional cost of the requested metering equipment including any incremental labor costs associated with installation of the requested metering equipment. Any such metering equipment must be approved by the Company.

Each unit of a new or renovated domestic structure with more than one dwelling unit will be metered separately and each meter will be billed as an individual customer. Where an individual household or business enterprise, occupation or institution occupies more than one unit of space, each unit will be metered separately and considered a distinct Customer, unless the Customer furnishes, owns and maintains the necessary distribution circuits by which to connect the different units to permit delivery and metering at one location of all the energy used.

The Company may for its own convenience install more than one meter per Customer, but in such cases the meter readings will be cumulated when billing.

In cases of non-access or where a meter fails to register the full amount of electricity consumed, the amount of the bill will be estimated by the Company, based upon the use recorded during previous months, or upon the best information available.

The Company may estimate, rather than meter, demand and kilowatt-hours used by a Customer where the demand and kilowatt-hour usage are constant and known or for locations which, in the Company’s judgment, are unsafe or impractical to separately meter or to access on a regular basis by Company personnel.

16. Customer Use of Electricity

In recognition of the fact that the wiring and facilities for the use of electricity on the Customer's premises are owned by and under the control of the Customer, the Company shall not be responsible for any loss, cost, damage, or expense to persons and/or property resulting from the use of or presence in the Customer's wiring or appliances, electricity delivered in accordance with the provisions of these Terms and Conditions and the Company's "Information and Requirements for Electric Supply"

If the Customer's requirements for electricity or use of service, or installation of Customer-owned equipment (including but not limited to motors, generation, meters, or capacitors) results in or is anticipated to result in damage to the Company's apparatus or facilities or electrical disturbances to other customers on the Company's distribution system, the Customer shall be responsible for the cost to the Company of repairing, replacing or upgrading the Company's facilities. If the Customer fails to correct for the interference with the operation of the Company's distribution system or with the electrical supply to other Customers, the Company reserves the right to refuse service or to disconnect service upon proper notice.

17. Compliance

Service hereunder is subject to the Customer's compliance with the following conditions:

(a) The Customer shall comply with or perform all of the requirements or obligations of this Tariff and the Company's "Information and Requirements for Electric Supply".

(b) The Customer shall allow the Company reasonable access to the Company's facilities located on the Customer's premises.

(c) The Customer shall comply with any applicable orders and regulations of the Commission.

(d) The Customer shall not cause or allow to exist any unauthorized or fraudulent use or procurement of the Delivery Service or any tampering with the connections or other equipment of the Company, or any condition on the Customer's premises involving the Delivery Service which is dangerous to health, safety or the electric service of others or which represents a clear and present danger to life, health, or physical property, or to the Company's ability to serve its other Customers.

(e) The Customer shall notify the Company when the Customer no longer desires Delivery Service.

18. Resale of Delivery Service

No customer shall sell, resell, assign or otherwise dispose of all or any part of the Delivery Service purchased from the Company without the written consent of the Company. The sale of electric vehicle charging services electricity to a third party from an electric vehicle charging station shall not be considered resale of electricity.

19. Company Property

The Company shall have the right to install, maintain and operate such Company-owned facilities on the premises of the Customer as in its judgment may be required to render Delivery Service to the Customer in accordance with this Tariff, whether such facilities shall be overhead or underground and whether the premises of the Customer are owned or leased to the Customer, and shall have the free right at all reasonable times to enter upon said premises for the purpose of maintaining, repairing, replacing or removing such facilities. Normally such facilities will consist of, but they shall not be limited to, overhead or underground service wires or cables extending to a Company-owned meter or meters and associated equipment.

Customer must provide, without expense or cost to the Company, the necessary permits, consents or easements satisfactory to the Company in order to install, maintain, repair, replace, or remove the Company's facilities on the Customer's property or property owned by others on which facilities are placed to serve the Customer.

If the Customer is a tenant or a mortgagor and his right of occupancy does not include authority to grant the Company the foregoing rights, he shall obtain his landlord's or his mortgagee's authority to grant the foregoing rights, and the Company may require that such authority be evidenced in writing by the landlord or mortgagee.

In the case of underground facilities, the Customer shall not erect or maintain or permit to be erected or maintained any building or structure over such facilities and shall not plant or permit to be planted any trees over such facilities.

20. Holidays

The following New Hampshire legal holidays shall be recognized as holidays for purposes of billing service in off-peak periods:

Holiday	Day Celebrated
*New Year's Day	January 1st
Martin Luther King, Jr. Civil Rights Day	Third Monday in January
Washington's Birthday	Third Monday in February
Memorial Day	Last Monday in May
*Independence Day	July 4th
Labor Day	First Monday in September
Columbus Day	Second Monday in October
*Veterans Day	November 11th
Thanksgiving Day	When appointed
*Christmas	December 25th

* If these days fall on Sunday, the following day shall be considered the holiday.

21. Conjunctional Service

Conjunctional Service is a Customer's use of Delivery Service under this Tariff for delivery of either Supplier Service or Default Service which supplements or is in addition to any other source of electric service connected on the Customer's side of the meter. Conjunctional Service must be taken in accordance with the Company's “Information and Requirements for Electric Supply” and the Company's technical guidelines and requirements pertaining to Qualifying Facilities ("QFs", as defined in Sections 201 and 210 of Title II of the Public Utility Regulatory Policies Act of 1978) filed with the Commission in compliance with Commission Order No. 14,797. Conjunctional service is available to QFs and to other Customers who are not QFs who have available another source of electric service connected on the Customer's side of the meter.

All Conjunctional Service furnished by the Company to Customers under this Tariff shall be taken by the Customers under the Rate Schedule which would otherwise be available for Delivery Service applicable to the total internal load of the Customer.

22. Conditions Under Which This Tariff is Made Effective

23. Customer Choice of Rate

Upon a Customer’s request, the Company shall provide information as to what may be the most advantageous rates and charges available to the Customer under this Tariff. However, the responsibility for the selection of a rate lies with the Customer and the Company does not warrant or represent in any way that a Customer will save money by taking service under a particular rate. The Company will not be liable for any claim that service provided to a Customer might have been less expensive or more advantageous to such Customer if supplied under another available rate.

24. Statement by Agent

No representative of the Company or Eversource Energy System Companies has the authority to modify any rule, provision or rate contained in this Tariff, or bind the Company for any promise or representation contrary thereto.

25. Third Party Claims and Non-Negligent Performance

Each Party agrees to indemnify and hold the other Party and its affiliated companies and the trustees, directors, officers, employees, and agents of each of them (collectively "Affiliates") harmless from and against any and all damages, costs (including attorneys' fees), fines, penalties, and liabilities, in tort, contract, or otherwise (collectively "Liabilities") resulting from claims of third parties arising, or claimed to have arisen, from the acts or omissions of such Party in connection with this Tariff. Each Party hereby waives recourse against the other Party and its Affiliates for, and releases the other Party and its Affiliates from, any and all Liabilities for or arising from damage to its property due to a non-negligent performance by such other Party.

26. Charges for Temporary Services

The Company shall have the right to charge the Customer for the total cost incurred in constructing and removing temporary services at locations under construction where the temporary service will not be converted to a permanent service. Such costs shall include the costs of labor, overheads and all materials except for the costs of transformers and meters. The Company shall not charge for the construction and removal of such temporary service whenever the temporary service is to be replaced at approximately the same location with a permanent service when construction is completed, provided that the permanent service is run from the same pole and utilizes the same material which was utilized for the temporary service.

27. Underground Service

Underground electric distribution facilities will be provided by the Company, in accordance with the provisions of the Company's “Information and Requirements for Electric Supply” and this Tariff, when feasible and practicable and when consistent with the normal availability of Company personnel, the orderly scheduling of construction projects, and all as reasonably determined by the Company. Subject to the above-stated limitations on the availability of underground facilities, such facilities will be provided by the Company on a consistent and equitable basis to all who qualify.

28. Diversion and Metering Tampering

If a Customer receives unmetered service as the result of any tampering with a meter or other Company equipment, the Company may take appropriate immediate corrective action without notice to the Customer, including making changes to the meter or other equipment. In addition, the Customer shall be subject to a meter diversion charge of $250, and may be required to reimburse the Company for lost revenue associated with the unmetered service, including late payment charges, damages to equipment, expenses incurred during the investigation, and may be subject to criminal prosecution.

29. Stranded Cost Recovery Charge

The Stranded Cost Recovery Charge (SCRC) is the portion of the unbundled retail delivery service bill that is a non-bypassable charge as provided by RSA 369-B:4,IV and RSA 374-F:3, XII to recover the portion of the Company’s Part 1 and Part 2 Stranded Costs that are allowed by the Settlement Agreement. The SCRC include the RRB Charge defined in RSA Chapter 369-B, over-market or under-market IPP and Power Purchase Agreement costs, Non-Securitized Stranded Costs, and other costs and expenses allowed or as authorized by the Commission.

Part 1 of the SCRC is the RRB Charge, and is the source of payment for Rate Reduction Bonds issued pursuant to RSA Chapter 369-B. One or more special purpose financing entities shall own the right to receive all collections in respect to the Part 1 charge. The Company will collect the RRB Charge in Part 1 of the SCRC on behalf of such special purpose financing entities. The special purpose financing entities’ ownership of the RRB Charge recovered via Part I of the SCRC will be reflected by an appropriate notation on customers’ bills. Part 1 of the SCRC will be billed until the rate reduction bonds issued by the special purpose financing entities and all on-going RRB Costs are paid in full.

Part 1 of the SCRC shall be adjusted as necessary via the True-Up mechanism approved by the Commission in its Order No. 26,099 in Docket No. DE 17-096, and such changes in Part 1 shall become effective as set forth in that Order.

Part 2 will recover all other non-securitized stranded costs and charges as approved by the Commission and will continue for as long as there are such costs to be recovered by the Company.

The SCRC shall be non-bypassable per RSA 369-B:4, IV and RSA 374-F:3, XII, and shall be collected from each retail customer of the Company. If a retail customer located in the Company’s service territory purchases or otherwise obtains retail electric service from any person other than the Company, including, without limitation, any successor referred to in RSA 369-B:8

the servicer or such new electricity service provider or successor shall collect the SCRC, from the retail customer by or on behalf of the Company and remit those revenues to the Company as a condition to the provision of retail electric service to such retail customer. Any retail customer that fails to pay the SCRC shall be subject to disconnection of service to the same extent that such customer would, under applicable law and regulations, be subject to disconnection of service for failure to pay any other charge payable to the Company.

The revenue requirement necessary to recover all Part 1 and Part 2 stranded costs will be allocated among rate classes as follows:

Rate Class	Percentage of Total Revenue Requirement
Residential Service (R, R-OTOD)	48.75
General Service (G, G-OTOD)	25.00
Primary General Service (GV, B*)	20.00
Large General Service (LG, B**)	5.75
Outdoor Lighting Service (OL, EOL)	0.50

*Rate B customers who would qualify for Rate GV except for their own generation.
**Rate B customers who would qualify for Rate LG except for their own generation.

The actual SCRC will vary by the rate schedule, may vary by separately metered rate options contained in certain rate schedules, may vary by time of use, and may include demand- as well as kWh-based charges. The Company, every six months, shall compare the amount to be recovered through the SCRC, as defined under the Settlement Agreement and this Tariff with the revenue received from the billing of the SCRC. Any difference between the amount to be recovered by Part 2 of the SCRC during any six month period and the actual revenue received during that period shall be refunded or recovered by PSNH with a return during the subsequent six month period by reducing or increasing Part 2 of the SCRC for the subsequent six month period. The return will be calculated using the Stipulated Rate of Return set forth in the Settlement Agreement.

If any customer class is materially reduced or consolidated to zero, its applicable allocation factor will be reallocated on a pro-rata basis between remaining rate classes based on the then current allocation responsibility.

The SCRC also includes the Regional Greenhouse Gas Initiative (“RGGI”) refund as required by RSA 125-O:23,II and Order No. 25,664 dated May 9, 2014, which directs the Company to refund RGGI auction revenue it receives to its Customers through the SCRC.

The SCRC also includes the costs of implementing 2018 N.H. Laws, Chapter 340, “AN ACT requiring the public utilities commission to revise its order affecting the Burgess BioPower plant in Berlin, … ” per Order No. 26,332 (“Ch. 340” costs). The revenue requirement necessary to recover Ch. 340 stranded costs will be allocated on an equal cents/kWh basis for all customer classes. Any difference between the amount of Ch. 340 costs to be recovered during any six month period and the actual revenue received during that period shall be refunded or recovered by

PSNH with a return during the subsequent six-month period by reducing or increasing Ch. 340 costs for the subsequent six-month period. The return will be calculated using the Stipulated Rate of Return set forth in the Settlement Agreement. Ch. 340 costs will continue for as long as there are such costs to be recovered from or refunded to customers by the Company.

The overall average SCRC by rate class and by component effective August 1, 2020 through January 31, 2021 are as follows:

Rate Class	Part 1 ¢/kWh	Part 2 ¢/kWh	Ch. 340 ¢/kWh	RGGI ¢/kWh	Total ¢/kWh
Residential Service	1.005	-0.507	0.607	-0.130	0.975
General Service	0.941	-0.534	0.607	-0.130	0.884
Primary General Service	0.777	-0.443	0.607	-0.130	0.811
Large General Service	0.293	-0.202	0.607	-0.130	0.568
Outdoor Lighting Service	1.196	-0.726	0.607	-0.130	0.947

30. Transmission Cost Adjustment Mechanism

The Transmission Cost Adjustment Mechanism (“TCAM”) will recover, on a fully reconciling basis, the costs incurred by the Company for transmission related services. These costs include charges under the ISO-NE Tariff; charges billed to the Company by Other Transmission Providers; third party charges billed to the Company for transmission related services such as charges relating to the stability of the transmission system which the Company is authorized to recover by order of the regulatory agency having jurisdiction over such charges; and transmission-based assessments or fees billed by or through regulatory agencies, including those associated with the ISO-NE, regional transmission organization ("RTO") and the FERC. For purposes of this mechanism, "Other Transmission Providers" shall be defined as any transmission provider and any regional transmission group, an independent system operator, an RTO and their successors, or other such body with the oversight of regional transmission, in the event that any of these entities are authorized to bill the Company directly for their services.

The TCAM rates shall be established annually based on a forecast of includable costs, and shall also include a full reconciliation with interest for any overrecovery or underrecovery occurring in the prior year. The Company may file to change the TCAM rates at any time if a significant overrecovery or underrecovery occurs. Interest on overrecoveries or underrecoveries shall be calculated at the prime rate.

Any changes to rates determined under the TCAM shall only be made following a notice filed with the Commission setting forth the amount of the increase or decrease, the new rates for each rate class, and the effective date of such new rates.

31. System Benefits Charge

On and after the Customer Choice Date, and subject to Commission review, all Customers shall be obligated to pay the following System Benefits Charge in addition to all other applicable rates and charges under this Tariff. The System Benefits Charge shall appear separately on all Customer bills.

System Benefits Charge.. 0.743 cents per kilowatt-hour

32. Regulatory Reconciliation Adjustment

The Regulatory Reconciliation Adjustment ("RRA") mechanism, shall recover or refund the reconciled costs associated with the following elements:

(a) Regulatory Commission annual assessments and consultants hired or retained by the Commission and OCA.
(b) Vegetation management program variances.
(c) Property tax expenses, as compared to the amount in base rates.
(d) Lost-base distribution revenues associated with net metering, as calculated consistent with RSA 362-A:9, VII and the Commission's approved method in Order No. 26,029 (June 23, 2017) in Docket No. DE 16-576.
(e) Storm cost amortization final reconciliation and annual reconciliation updated for actual cost of long-term debt.

The RRA shall be established annually based a full reconciliation with interest for any over- or under-recoveries occurring in prior year(s). Interest shall be calculated at the prime rate, to be fixed on a quarterly basis and to be established as reported in The Wall Street Journal on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used. There will be no adjustment for Accumulated Deferred Income Tax ("ADIT") in the interest calculation. For purposes of billing under the alternative net metering tariff that became effective September 1, 2017, the RRA will be considered part of the credit to net metering customers.

33. Late Payment Charge

The rates and charges billed under this Tariff are net, billed monthly and payable upon presentation of the bill. However, Customers who receive Delivery Service under Residential Rate R, Residential Time-of-Day Rate R-OTOD, General Service Rate G, or General Service Time-of-Day Rate G-OTOD may elect to pay for all service rendered under these rates, as well as Default Energy Service, on a Level Payment Plan available upon application to the Company.

For Customers rendered Delivery Service under Primary General Delivery Service Rate GV or Large General Delivery Service Rate LG or Backup Delivery Service Rate B, all amounts previously billed but remaining unpaid after the due date printed on the bill shall be subject to a late payment charge of one and one-half percent (1 ½ %) thereof, such amounts to include any prior unpaid late payment charges. For all other Customers, all amounts previously billed but remaining unpaid after the due date printed on the bill shall be subject to a late payment charge of one percent (1%) thereof, such amounts to include any prior unpaid late payment charges. The late payment charge is not applicable to a) residential Customers who are taking service under the statewide Electric Assistance Program (EAP) as approved by the Commission; b) residential Customers receiving protection from disconnection of service under any enhanced winter protection programs offered by the Company; c) residential Customers whose electric bill is paid on their behalf (whether in part or in whole) through the Low Income Home Energy Assistance Program (LIHEAP); and d) past due balances of Residential Rate R, Residential Time-of-Day Rate R-OTOD, General Service Rate G, General Service Time-of-Day Rate G-OTOD, Outdoor Lighting Rate OL, or Energy Efficient Outdoor Lighting Rate EOL Customers who are abiding by the terms of an extended payment arrangement agreed to by the Company.

34. Loss of Service Investigation Charge

For Customers rendered Delivery Service under Primary General Delivery Service Rate GV, Large General Delivery Service Rate LG or Backup Delivery Service Rate B:

If at the request of a Customer, the Company responds to investigate any loss of electric service at the Customer's premises, and finds the interruption of service has been caused by the Customer's equipment, the Company shall charge the Customer for the total cost incurred to investigate the loss of service.

35. Rates for Purchases from Qualifying Facilities

Availability:

This short-term purchase arrangement shall be available to Qualifying Facilities (QFs) interconnected with the Company. Qualifying Facilities shall mean small power producers and cogenerators that meet the criteria specified by (i) FERC in 18 C.F.R. §§ 292.203 (a) and (b); or; (ii) the definition of "limited producer" or "limited electrical energy producer" in NHRSA 362-A:1-a and who meet the requirements of RSA 362-A:3, II.

Nothing shall prohibit the Company from separately contracting for generation purchases from QFs. Nothing herein shall be construed to affect, modify or amend terms and conditions of an existing Qualifying Facility's contract or rate order with respect to the sale of its energy or capacity.

Selling Options:

QFs may sell to the Company or wheel through the Company. All generation sold to the Company shall be resold at the ISO-NE market clearing price and subject to appropriate charges as if the power was wheeled through the Company and sold directly to ISO-NE.

Metering:

Generators selling to the Company shall install metering as specified by the Company to satisfy ISO-NE requirements as they may change from time to time. Projects shall be charged a standard monthly service fee for metering service as approved by the appropriate regulatory agency.

Net Metering:

Projects 1,000 kilowatts and under using renewable generation shall have the option of being served under the Net Energy Billing Service as specified by NH RSA 362-A:9 and the rules promulgated by the appropriate regulatory agency.

<u>Projects receiving a utility net metering capacity allocation prior to March 2, 2017</u> and not in excess of the applicable net metering cap will continue to be billed and receive credit for their generation in accordance with RSA 362-A:9 and Puc 903.02(f) and Puc 903.02(g) (the “Standard Net Metering Tariff”) through December 31, 2040.

<u>Projects receiving a utility net metering capacity allocation beginning on March 2, 2017 and ending on August 31, 2017</u> and not in excess of the applicable net metering cap will continue to be billed and receive credit for their generation in accordance with the interim alternative net metering tariff adopted by the Commission in Order No. 25,972 (December 21, 2016) (the “Interim Net Metering Tariff”) through December 31, 2040.

<u>Projects receiving a utility net metering capacity allocation on or after September 1, 2017</u> will be billed and credited under the “Alternative Net Metering Tariff” provisions described below once the Company is capable of implementing these provisions. Until such time, customers will be billed and credited under the Standard Net Metering Tariff. Customers receiving a net metering capacity allocation while this Alternative Net Metering Tariff is in effect will be entitled to the net metering design and structure then in effect through December 31, 2040.

1. Eligibility

   A customer-generator whose facility has a total peak generating capacity less than or equal to 100 kilowatts is eligible to participate as a small customer-generator.

   A customer-generator whose facility has a total peak generating capacity greater than 100 kilowatts up to and including 1,000 kilowatts is eligible to participate as a large customer-generator if they consume at least twenty percent (20%) of their actual or estimated annual system electric production on-site and behind the meter. Otherwise, the customer must register as a group host under RSA 362-A:9, XIV. A large customer-generator meeting the on-site consumption threshold may switch to the Alternative Net Metering Tariff upon written notice of such election to the Company.

2. Metering

   The Company will install a bidirectional meter to record in separate channels the quantities of electric imports from the distribution utility grid and electric exports to the distribution utility grid over a billing period. At the time of interconnection, a customer may request, at no cost, installation of a Company-owned production meter. The Customer must provide and install an appropriate meter socket in a physical location acceptable to the Company.

3. Billing

   Customers will be billed in accordance with the delivery and energy service rate schedules that would apply in the absence of generation, except as specifically provided otherwise hereunder.

   During each billing period, credits for electricity exports will be issued in the form of monetary bill credits which will carry forward on a customer's account from month to month until used. Customers may receive a cash payment for any accumulated excess credit when they move or discontinue service, or on an annual basis if they have accumulated a credit balance in excess of $100 as of the end of the March billing cycle.

   <u>Small customer-generators</u> will be assessed the Stranded Cost Recovery Charge and System Benefits Charge based on the full amount of their electricity imports without any netting of exports during the billing period.

   All other kilowatt-hour-based rate components will be assessed on the customer's net energy usage, which is the quantity of kilowatt-hours equal to electric imports minus electric exports (if positive).

   If such net energy usage is less than zero, customers that receive Default Energy Service from the Company will receive a monetary bill credit for their net electric exports during each billing period calculated at twenty-five percent (25%) of any Distribution charges assessed on a per-kilowatt-hour basis; any Transmission charges assessed on a per-kilowatt-hour basis; and the Default Energy Service Rate.

If net energy usage is less than zero, customers that do not receive Default Energy Service from the Company will receive a monetary bill credit for their net electric exports during each billing period calculated at twenty-five percent (25%) of any Distribution charges assessed on a per-kilowatt-hour basis; and any Transmission charges assessed on a per-kilowatt-hour basis.

Large customer-generators will be assessed all charges associated with their rate class based on the full amount of their electricity imports without any netting of exports during the billing period. Customers who receive Default Energy Service from the Company will receive a monetary bill credit for their electric exports during each billing period calculated at the Default Energy Service Rate.

For both Small and Large customer-generators, a competitive Energy Service Provider may determine the terms, conditions and prices under which it agrees to provide generation supply to and purchase net generation output from the customer-generator.

4. Grandfathering Provisions

Subsequent sales or other transfers of ownership of a net-metered system or the property upon which the system is located shall not impact the terms and conditions under which the customer-generator is rendered net metering service. New owners shall be allowed to continue to take service under the same terms and conditions in effect at the time of such sale or transfer until 2040, in accordance with RSA 362-A:9,XV and Order No. 25,972, or pursuant to Order No. 26,029, provided that the system is not moved to a different location by the purchaser, transferee, or otherwise.

Residential small customer-generators may expand their systems without limitation, provided that the expansion does not result in total system capacity in excess of 100 kW.

Non-residential small customer-generators may expand the capacity of their systems by an amount up to the greater of either 20 kW or 50 percent of the system capacity allocated into the standard net metering program prior to September 1, 2017, or the original capacity of a system installed under the alternative net metering tariff effective as of September 1, 2017, as applicable, provided that in neither case can any such expansion have the effect of increasing the system's capacity to an amount in excess of 100 kW.

Non-residential large customer-generators may expand the capacity of their systems by an amount up to the greater of either (1) 50 kW, or (2) a capacity amount such that the expanded system is sized to produce 110 percent of the customer-generator's annual kilowatt-hour on-site usage, as clearly demonstrated through the customer-generator's documentation of any consecutive 12-months within the previous two years.

In neither case, can any such expansion have the effect of increasing the system's capacity to a level in excess of one megawatt. Expansion of a net-metered system by or for a commercial or industrial customer-generator smaller than the applicable limitation will allow the customer-generator to continue to be grandfathered, while any such expansion in excess of the applicable limitation will result in the entire net-metered system losing its net metering grandfathered status.

Any system modifications must be reported to the Company within 30 days of modification or earlier if so required under the Company's distributed generation interconnection procedures.

5.Renewable Energy Certificates

The Company will offer to serve as independent monitor for a customer-generator who elects to receive a Company-owned production meter. The Company will report the electricity production of such customer-generator at least quarterly to NEPOOL-GIS at no cost to the customer. The Company will file an application on behalf of the customer for Commission certification of the eligibility of the installation to produce renewable energy certificates pursuant to RSA 362-F and the Commission's Puc 2500 rules. Any customer requesting a Company-owned production meter or requesting the Company to serve as the independent monitor must respond in a timely manner to requests for information from the Company.

Rates:

Qualifying Facilities selling their output to the Company will be eligible to receive Short Term Avoided Cost Rates equal to the payments received by the Company for the sale of QF generation to the ISO-NE power exchange, adjusted for line losses, wheeling costs and administrative costs incurred by the Company for the transaction. Projects shall be charged a standard monthly service fee for billing service as approved by the appropriate regulatory agency.

Wheeling Charges:

The Company reserves the right to impose any appropriate wheeling charges (including distribution wheeling charges) for generation transmitted through the Company and sold to ISO-NE and others as may be approved by the appropriate regulatory agency.

36. Line Extensions

In areas in which Delivery Service by the Company is authorized, the Company will extend its single-phase or three-phase distribution facilities or upgrade its single-phase distribution facilities to three-phase distribution facilities to a maximum of 5,280 feet in length to serve Customers under Residential Delivery Service Rate R and Rate R-OTOD and General Delivery Service Rate G and Rate G-OTOD, at their request. Extensions or upgrades greater than 5,280 feet in length will be constructed at the discretion of the Company.

Additionally, per RSA 370:12, customers requiring a line extension on private property may opt to hire and pay a private line contractor, licensed by the state and approved by the Company, to construct a required overhead or underground power line extension on private property. The contractor shall supply and install all materials as specified by the Company. Line extensions must be designed by the Company and built to its specifications in order for the Company to assume ownership of the line. The Company has the right to not accept a customer built line extension that does not conform to the Company's specifications. Customers may not contract with private line contractors to construct line extensions along public ways.

1. Location of Distribution Facilities

The order of preference for the location of line extensions are (i) along public ways; (ii) along private roads maintained year-round; (iii) along private roads maintained on a seasonal basis; (iv) over rights of way accessible by standard Company equipment; and (v) over rights of way not accessible by standard Company equipment. The Company may choose a higher preference location even if a lower preference location may result in a shorter line extension. The final placement of all line extensions must be preapproved by the Company.

2. Calculation of Line Extension Construction Costs

Definitions

<u>Overhead Service Drop</u>: The final span of cable providing secondary voltage to a Customer's meter or point of attachment location, whichever is applicable, from a utility pole. The maximum length of an overhead service drop is determined by the characteristics of the Customer's load and the terrain over which the overhead service drop passes.

<u>Underground Service Drop</u>: The final run of cable providing secondary voltage to a Customer's meter from a transformer or from a secondary conductor located on the Company's distribution system.

Distribution Facilities Provided by the Company at No Charge to the Customer

There shall be no separate charge for a pole-mounted transformer which the Company determines is needed to adequately serve a Customer's load and up to 300 feet of distribution facilities. The 300 feet of distribution facilities must include the length of an Overhead or Underground Service Drop currently being installed to serve a customer premise.

Additional Distribution Facilities

Any overhead or underground distribution facilities required to serve a Customer in addition to a pole-mounted transformer and up to 300 feet of distribution facilities as defined above, are subject to the charges specified below.

<u>Adding Additional Phases to Existing Overhead Single-phase Facilities</u>
The estimated cost in excess of 300 feet of distribution facilities, including the length of an Overhead Service Drop shall be derived based on the Customer-specific job requirements and shall include all costs related to the construction of the distribution facilities, including but not limited to design and inspection and construction labor; researching and recording easements; materials; traffic control; tree trimming; blasting and overheads.

<u>Overhead Single-Phase Facilities</u>
The estimated cost shall be derived by multiplying the length of the distribution facilities by the average cost per foot of overhead single-phase distribution facilities based on the following schedule of charges. The length of the distribution facilities shall be based on the length of single-phase primary and secondary line to be installed in excess of 300 feet, including the length of an Overhead Service Drop.

Effective Dates	Overhead, Single-Phase Average Cost per Foot
April 1, 2020 – March 31, 2021	$29.51
April 1, 2021– Forward	See section “Average Cost per Foot Effective From April 1, 2021– Forward”

<u>Overhead Three-Phase Facilities</u>
The estimated cost in excess of 300 feet of distribution facilities, including the length of an Overhead Service Drop shall be derived based on the customer-specific job requirements and shall include all costs related to the construction of the distribution facilities, including but not limited to design and inspection and construction labor; researching and recording easements; materials; traffic control; tree trimming; blasting and overheads.

<u>Underground Single-Phase Facilities</u>
The estimated cost shall be derived by multiplying the length of the distribution facilities by the average cost per foot of underground single-phase distribution facilities based on the following schedule of charges and adding the result to the excess cost of any padmounted transformers to be installed. The length of the distribution facilities shall be based on the length of single-phase primary and secondary line to be installed in excess of 300 feet, including the length of an Underground Service Drop. The excess cost of a padmounted transformer is the amount by which the cost of a padmounted transformer exceeds the cost of an equivalent pole-mounted transformer. The Company will determine the excess cost on the basis of average cost formulas consistently and equitably applied to all underground installations.

Effective Dates	Underground, Single-Phase Average Cost per Foot
April 1, 2020 – March 31, 2021	$16.22
April 1, 2021 – Forward	See section “Average Cost per Foot Effective From April 1, 2021 – Forward”

Underground Three-Phase Facilities
The estimated cost in excess of 300 feet of distribution facilities, including the length of an Underground Service Drop shall be derived based on the customer-specific job requirements and shall include all costs related to the construction of the distribution facilities, including but not limited to design and inspection and construction labor; researching and recording easements; materials; traffic control; tree trimming; blasting, overheads and the excess cost of any padmounted transformers to be installed. The excess cost of a padmounted transformer is the amount by which the cost of a padmounted transformer exceeds the cost of an equivalent pole-mounted transformer. The Company will determine the excess cost on the basis of average cost formulas consistently and equitably applied to all underground installations.

Average Cost per Foot Effective From April 1, 2021 - Forward
The Company will update the overhead single-phase and underground single-phase average cost per foot figures for effect on April 1 based upon a sampling of actual line extensions completed in the preceding three calendar years using the methodology contained in the Settlement Agreement in Docket No. DE 08-135 and as approved by the Commission in its Order No. 25,046 dated November 20, 2009. All costs related to the construction of the distribution facilities will be included in the average cost per foot figures, including but not limited to design and inspection and construction labor; researching and recording easements; materials; traffic control; tree trimming; blasting and overheads.

3. Customer Responsibilities

i) Payments: The Customer is responsible to pay to the Company their proportional share of any line extension construction costs in accordance with any line extension agreements in effect when service is requested by the Customer (for line extensions constructed after September 1, 2016) prior to the start of the Company's construction. In addition, the Customer is responsible to pay to the Company any line extension construction costs as defined in section 2 above and any special costs as defined in section ix below prior to the start of the Company's construction if the total cost is $3,000 or less. If the total cost is greater than $3,000, the Customer has the option to either pay the total amount prior to the start of construction, or to sign an agreement to pay the amount in excess of $3,000 in 60 equal monthly payments, plus interest at the rate of interest applicable to the Company's Customer deposit accounts at the time of execution of the agreement ("Line Extension Monthly Surcharge"). The Company reserves the right to place a lien on the property until such time that the payment obligation is fulfilled. The Customer must agree, as a condition of the line extension monthly payment option, that if the Customer sells, leases or otherwise transfers control and use of the home to another individual ("New Occupant"), and such "New Occupant" opens a new account with the Company, the Customer will obtain an agreement from the "New Occupant" to pay the remaining balance as prescribed in the agreement that would have been owed by the Customer at that location. Unless the "New Occupant" signs a new superseding payment agreement with the Company, the original Customer will remain personally liable for the balance owed to the Company. Any retail Customer that fails to pay the Line Extension Monthly Surcharge shall be subject to disconnection of service to the same extent that such Customer would, under applicable law and regulations, be subject to disconnection of service for failure to pay any other charge payable to the Company..

ii) Easements: The Customer is responsible to provide, without expense or cost to the Company, the necessary permits, consents or easements for a right-of-way satisfactory to the Company on the Customer's property for the construction, maintenance and operation of the Company's distribution facilities, including the right to cut and trim trees and bushes.

iii) Environmental Permits: The Customer is responsible to provide, without expense or cost to the Company, the necessary environmental permits for the construction, maintenance and operation of the Company's distribution facilities on the Customer's property.

iv) Plans: The Customer is responsible to provide the Company with details of the intended installation, including property lines, building locations, service entrance specifications and major electrical load information.

v) Other Documents: If the Customer intends to use an existing easement area to cross the property of others with the Company's distribution facilities, the Customer is responsible to provide evidence that the easement permits the installation of such facilities by the Company.

vi) Code Compliance: The Customer is responsible to obtain the necessary approvals from the local inspection authorities before the Customer's service entrance equipment is connected to the Company's distribution system.

vii) Site Plans: Developers must provide to the Company a site plan or other documentation identifying the maximum number of lots or self-contained living units. The developer shall also provide the Company additional notice should the number of lots or living units increase or decrease from the initial documentation. The developer is responsible to pay any additional costs, including design costs, resulting from changes to the number of lots or units developed subsequent to the original documentation. Upon request, all other Customers requesting service shall provide a site plan for the Company to design the distribution facilities.

viii) Underground Distribution Facilities: The Customer shall furnish to the Company's specifications all trench excavation, back-fill, conduit, duct bank, manholes, vaults, pedestals and transformer foundations necessary for the installation of underground electric distribution facilities. Underground distribution facilities shall be provided in accordance with the Company's "Information and Requirements for Electric Supply".

ix) Special Costs: The Customer shall pay for all costs incurred by the Company for extensions that require construction which would result in special costs, such as railroad or National Forest crossings, crossing rivers and ponds, crossing wetlands, extending to an island, use of submarine cable or any additional costs incurred to protect the environment and comply with the Company's environmental policy and procedures.

x) The Customer shall be responsible for any other requirements as specified in the Company's "Information and Requirements for Electric Supply".

4. Company Responsibilities

   The Company shall be responsible for:

   i) Constructing and maintaining the electric distribution facilities to serve the Customer's premises.

   ii) Trimming trees and bushes to the Company's standards along the route of the overhead distribution facilities, including the Overhead Service Drop serving the Customer's premises.

All distribution facilities constructed under the provisions of this line extension section shall be and shall remain the property of the Company. The Company shall not be required to install distribution lines, transformers, Service Drops or meters under the above terms in locations where access is difficult by standard Company distribution construction and maintenance vehicles, where the service does not comply with the Company's environmental policy and procedures, where it is necessary to cross a body of water or to serve airport lighting, beacon lighting, street lighting or where the business to be secured will not be of reasonable duration or will tend in any way to constitute discrimination against other Customers of the Company.

37. Interconnection Standards For Generating Facilities

Any person or entity planning to operate a generating facility and connect it to the Company's facilities must receive approval from the Company prior to connecting the generating facility to the Company's facilities. A generating facility is any device producing electrical energy which can range in size from a small, residential photovoltaic solar installation to a large commercial generating facility. Inverter-based generating facilities sized up to 100 KVA must meet the requirements contained in the Company's "Interconnection Standards for Inverters Sized Up to 100 KVA", as approved by the Commission. The Standards provide information on the application process, time-lines and technical requirements and are available at the Company's web site at www.eversource.com. For all other generating facilities, the Company must be contacted for site specific interconnection requirements prior to interconnecting the generating facilities with the Company's facilities.

TERMS AND CONDITIONS FOR ENERGY SERVICE PROVIDERS

The following terms and conditions shall apply to Energy Service Providers ("Suppliers") doing business within the Company's Service Area and to Customers where specified.

1. Obligations of Suppliers

a. At all times, the Supplier must meet the registration and licensing requirements established by law and/or by the Commission and must comply with all applicable rules promulgated by the Commission.

b. The Supplier or the Customer in the case of Self-Supply Service must be either a member of NEPOOL or have an agreement in place with a NEPOOL member whereby the NEPOOL member agrees to take responsibility for all the NEPOOL load obligations, including but not limited to losses and uplift costs, associated with supplying energy and capacity to the Customer's delivery point.

c. The Supplier or the Customer in the case of Self-Supply Service shall be responsible for providing all the capacity and energy needs of the Customer and shall be responsible for any and all losses which include all distribution and transmission losses along the Local Network from the PTF Facilities to the Customer's delivery point.

d. The Supplier shall provide the Company with at least 30 days' notice prior to either the cancellation of an agreement for load responsibility with NEPOOL or a NEPOOL member, or the termination of business in the Company's Service Area. The Supplier shall accept load responsibility for all its Customers, or have an agreement with a NEPOOL member which provides for accepting load responsibility for all its Customers, until the first meter read date for each respective customer occurring two business days after notice to the Company or transmittal of any Electronic Data Interchange ("EDI") to the Company.

e. In the case of Self-Supply Service the Customer shall provide the Company with at least 30 days' notice prior to the cancellation of an agreement for load responsibility with either NEPOOL or a NEPOOL member. The Customer shall accept load responsibility or have an agreement with a NEPOOL member which provides for accepting load responsibility for the Customer until the Customer's first meter read date occurring at least two business days after notice has been received by the Company from the Customer.

f. The Supplier shall satisfy all the EDI standards as approved by the Commission. A Supplier shall be required to complete testing of EDI transactions prior to the rendering of Supplier Service to any Customer.

g. The Supplier shall be responsible for reviewing and confirming the accuracy of all data provided to, or made available for, inspection to the Supplier by the Company during the load estimation, load reporting, billing and other processes described in these Terms and Conditions and/or ISO-NE's Rules.

g. Each Supplier shall be required to enter into a service contract with the Company that resolves issues associated with, among other things, information exchange, problem resolution and revenue liability. This contract must be entered into prior to initiation of Supplier Service to any Customer in the Company's Service Area.

h. The Supplier shall be responsible for obtaining the Customer's authorization, in accordance with the Commission's rules, prior to the commencement of Supplier Service.

i. The Supplier shall be responsible for obtaining the Customer's written authorization for the release of the Customer's load history to the Supplier by the Company.

In the event a Supplier doing business in the Company's Service Area fails to comply with the obligations specified above, the Supplier shall promptly notify the Company or the Company will promptly notify the Supplier. The Supplier shall undertake best efforts to re-comply with its obligations under this Tariff and the Commission's rules in a timely manner. Until the Supplier has re-satisfied its obligations, the Company reserves the right to deny any new customer enrollments from the Supplier. In the event the Supplier is unable or unwilling to re-satisfy its obligations, the Company may transfer the Suppliers' Customers to service under Default Service after notification to the Commission.

2. Services and Schedule of Charges

Where applicable, the Customer and/or Supplier will be obligated to pay the following fees and charges to the Company for the following services:

(a) Customer Usage Data

Suppliers will be provided with monthly usage data, at no charge, via an EDI transaction in accordance with the guidelines adopted by the Commission. The Supplier is responsible for obtaining the Customer's written authorization to release this information and will be required to maintain the confidentiality of the Customer information. The Supplier may not sell or provide this information, in whole or in part, to another party.

(b) Interval Data Services

The Company will provide the following Interval Data Services for Suppliers and Customers who wish to acquire, develop or analyze time interval meter data from the Company's meter installed at the Customer's service location. The following services are limited to those service locations with interval data recorders installed. The interval data will be provided in 30 minute intervals.

The Supplier is responsible for obtaining the Customer's authorization to release his/her meter data and shall maintain the confidentiality of Customer information. The Supplier may not sell or provide this information, in whole or in part, to another party.

1. Interval Data Access Service

(i) Subscription Service for Interval Data via Electronic Mail (E-mail), U.S. Mail or Internet Server

The Company will provide the monthly interval data in an electronic format to the Customer or Supplier via E-Mail, U.S. Mail, or the Company will post the monthly interval data files to an internet server designated by the Company. The Customer or Supplier is responsible for downloading the file containing the interval data from the internet server.

Single Delivery Service Account..............................$25.00 per Month*

*At Supplier's option, a $300 annual charge may be assessed in lieu of the $25 monthly charge.

(ii) One-Time Request for Interval Data

If available, the Company will provide a Customer's historical interval data in an electronic format to the Customer or Supplier at the following rate:

Single Delivery Service Account..............................$50.00 per Request

2. Load Pulse Outputs Service

This service is offered to Customers or Suppliers who desire a pulse output from the Company's meter. The Company will acquire and install the equipment to allow the Customer or Supplier to interface with the Company's metering equipment and enable the Customer or Supplier to have access to load pulse output. Pulses representing kilowatt-hours are usually requested, but other electrical quantities such as kilovar-hours are also available. The Customer or Supplier has the option to connect this output to their own interval data recorder or other load monitoring or load management devices. The Customer or Supplier is responsible for connecting their own devices to the load pulse output. The one-time fee
for this service is as follows:

Load Pulse Output
Up to Two Metered Quantities.....................................$800 per Isolation Relay Device

(c) Supplier Customer Service

The Company will provide Customer Service, as an optional service, to Suppliers who have entered into a written agreement for Billing and Payment Service with the Company and who have entered into a written agreement for Supplier Customer Service with the Company for a minimum of one year. Customer Service is defined as processing of standard Customer informational requests on behalf of a Supplier including Supplier balances, rate information, resolving disputes and processing Customer enrollment. This service is available for Supplier's Customers located within the Company's Service Area. This service includes inbound calls and does not include outbound telemarketing service to potential Customers or promoting new Supplier services to existing Customers. The charges shall be assessed monthly and based on minutes of call handling time as follows:

Supplier Customer Service Charge ....$1.10 per minute

Nothing herein shall prohibit the Company and Supplier from negotiating an annual per customer fee for Customer Services. The Supplier will be responsible for establishing a separate toll free number to allow the number of calls to be tracked as well as allowing for individualization of services.

(d) Billing and Payment Service

The Company will provide Billing and Payment Service as an option to Suppliers who have entered into a written agreement for Billing and Payment Service with the Company for a minimum of one year. The monthly Billing and Payment Service Charge, listed below, is for billing arrangements which can be accommodated by the Company's billing systems without significant programming changes:

Billing and Payment Service Charge ....$ 0.07 per bill rendered
Minimum Billing and Payment Service Charge ....$ 100.00 per month

The Company shall also provide, at its option, Billing and Payment Service for Supplier pricing options which require programming changes to the Company's billing systems. Suppliers will be assessed a one-time setup charge at the following rate to enable non-standard Supplier billing arrangements by the Company:

Programming Setup Charge..$95.00 per hour

Any request by the Supplier for Rate Maintenance and Error Correction service provided by the Company in support of Billing and Payment Service will be billed on a monthly basis using the hourly rate below. Rate Maintenance and Error Correction will include maintaining Supplier rates and pricing options in the Company's billing systems and calculating Customer billing adjustments due to Supplier errors in pricing.

Rate Maintenance and Error Correction Charge....................$53.00 per hour

Customer payments received by the Company shall be applied to balances due to the Company and the Supplier in the following order:

(1) utility outstanding deposit obligations, (2) any utility current payment arrangement obligations, (3) any utility budget billing arrangement obligations, (4) utility and supplier aged accounts receivables, with a priority for the utility aged receivables, (5) utility and supplier current charges, with a priority for the utility's current charges, and (6) any miscellaneous nonelectric service product or services.

(e) Off-Cycle Meter Reading

In the event of non-payment by a Customer receiving Delivery Service under Large General Delivery Service Rate LG, a Supplier shall be permitted to request an off-cycle meter reading by the Company pursuant to the notice requirements and terms provided in Rule Puc 2004.12. Suppliers will be assessed the following charge:

Off-Cycle Meter Reading Charge (if telemetered) $53 per meter
Off-Cycle Meter Reading Charge (if non-telemetered) $84 per meter

3. Initiation and Termination of Supplier Service

(a) Initiation

To initiate Supplier Service to a Customer, the Supplier shall submit an Electronic Enrollment which shall comply with the EDI standard, as may be amended from time to time.

If the information on the Electronic Enrollment passes validation, the Company will send the Supplier a "Successful Enrollment" notice. Supplier Service shall commence on the date of the Customer's next meter read date, provided that the Supplier has submitted the Electronic Enrollment to the Company at least two business days prior to the scheduled meter read date. If the Company receives more than one Electronic Enrollment for the same Customer for the same enrollment period, the first successfully processed Electronic Enrollment shall be accepted. All subsequent Electronic Enrollments received during that enrollment period shall be rejected.

If a Supplier's Electronic Enrollment fails to meet the requirements of this Tariff, the Company shall, within one business day of receipt of the Electronic Enrollment, notify the Supplier through an EDI Error notice.

(b) Termination

To terminate Supplier Service with a Customer, the Supplier of record shall submit electronically to the Company a valid “Supplier Drops Customer” transaction. Supplier Service shall terminate on the date of the Customer’s next meter read date, provided that the “Supplier Drops Customer” transaction is submitted and successfully processed at least two business days prior to the Customer’s scheduled meter read date. If the “Supplier Drops Customer” transaction is not received at least two business days prior to the scheduled meter read date, Supplier Service will terminate on the subsequent meter read date. The Company shall send a “Confirm Drop Date” transaction to the Supplier of record. The Supplier of record will be responsible for notifying the Customer of the termination date.

In cases where the Company uses estimated energy and demand values for billing purposes and the estimated bill coincides with the termination of Supplier Service, the Supplier shall agree to accept the estimated metering values as final values. The Company shall not be obligated to reconcile the estimated values after actual meter reading values are available.

(c) Customer Moves

If a Customer of record moves within the Company’s Service Area and the Customer or designee notifies the Company prior to the initiation of Delivery Service at the new service location that he/she wishes to continue Supplier Service with the Supplier of record, the Company shall send a “Customer Move” notice to the Supplier and no Electronic Enrollment is necessary for the continuation of Supplier Service.

If a Customer of record initiates Delivery Service at a new service location, in addition to another established account within the Company’s Service Area, the Customer shall be responsible for selecting a Supplier for the new service location. If an Electronic Enrollment is not received by the Company at least two business days before the initiation of Delivery Service, the Customer will be rendered energy and capacity under Default Service.

Unless the Company is notified otherwise by the Customer, the Company treats all applications for Delivery Service as a new Customer to the Service Area and the Customer will be rendered energy and capacity under Default Service at the new service location. In the event the Company is informed that the new application for Delivery Service is a Customer of record on or after the date Delivery Service is initiated, the Supplier will be notified either by the Customer Usage Information or the Customer Usage and Billing Information EDI transactions, if and when Delivery Service is terminated at the prior service location.

(d) Other

In the event a Delivery Service account is terminated by either the Customer or the Company, such termination will be shown on either the Customer Usage Information or the Customer Usage and Billing Information EDI transactions.

4. Exclusion of Supplier From Providing Service Within the State of New Hampshire or From the Regional Market

In the event of a Supplier's Default that has led to a Suspension from regional market participation by ISO-NE or another event causing a Supplier to be unable to provide service to its customers in New Hampshire, the Company shall transfer all Customers of the Supplier to Default Energy Service as of the effective date provided by ISO-NE or the Commission, as applicable, otherwise known as the transfer date. Such Suppliers will be assessed a customer transfer charge. Transferred Customers shall remain on Default Energy Service until the Company receives a valid Electronic Enrollment from a registered Supplier or notice from the Customer in the case of Self-Supply Service. The Company shall require a new signed service agreement with any Supplier that has been Suspended and has subsequently been reinstated by ISO-NE, or if another event caused a Supplier to be unable to provide service to its customers and that event was subsequently cured. Electronic Enrollments from Suppliers reinstated by ISO-NE or the Commission shall be effective no sooner than thirty days from the transfer date provided by ISO-NE or the Commission, unless agreed to by the Company.

Customer Transfer Charge: $64 per service account

5. Interruption, Disconnection and Refusal of Delivery Service

Any interruption, disconnection and refusal of Delivery Service by the Company shall be in accordance with this Tariff and the rules of the Commission. The Company shall not be liable for any revenue losses to Suppliers as a result of an interruption or disconnection of Delivery Service to an existing Customer.

In the event the Company refuses to supply or expand Delivery Service for any reason, the Company shall not be responsible for any losses or damages (direct, indirect or consequential) to a Supplier resulting from the corresponding loss of compensation.

6. Metering

The Company shall meter each Customer in accordance with Tariff provisions. Each Customer shall be metered or its load estimated such that the loads can be reported to the ISO-NE for inclusion in the Supplier's, or applicable NEPOOL member's, load calculations.

In the event a Supplier utilizes the Company's meter readings for billing purposes, the Company shall not be responsible for any loss or damage to a Supplier resulting from a failure of the Company's metering equipment to partially or fully register the amount of electricity consumed by a Customer.

Should a Supplier install metering equipment or any other equipment on Customer-owned facilities which interferes with the operation of the Company's metering equipment or any other Company-owned equipment, the Supplier shall undertake best efforts to remedy the interference in a timely manner and shall compensate the Company for any damages resulting from the interference. Failure to remedy the interference may result in the termination of Delivery Service after 30 days' notice to the Supplier and Customer.

The Company is not obligated to use metering data registered by Supplier-owned metering equipment for the purpose of billing Delivery Service under this Tariff or for reporting load to ISO-NE.

7. Determination of Hourly Loads for ISO-NE Reporting (Estimation)

The determination and subsequent reporting of Supplier loads (which includes the coincident peak capacity values) shall be in accordance with NEPOOL/ISO-NE Market Rules and Procedures, and State regulations. Each Supplier's loads will be assigned to a specific load asset (as registered with ISO-NE) and the corresponding hourly values will be reported to ISO-NE for financial settlement of the wholesale electricity market, and appropriate regulatory bodies. Courtesy copies of this data may be provided to each Supplier.

Load settlement is performed using a combination of actual hourly interval meter data and estimated data. The multi-step process includes the determination of the (i) Retail Territory Load (as said term is defined in Section A below), (ii) Customer loads, and (iii) Supplier loads, as well as any adjustments to those values. A description of each of these steps follows.

(a) Determination of the Retail Territory Load (Real Time Market Settlement)

On an hourly basis, the Company will calculate an aggregate value representing the load of its Customers served below the 345kV transmission system (the "Retail Territory Load") at the PTF boundary with the Company Metering Domain(s). The Retail Territory Load will consist of the five components below as represented in the ISO-NE settlement system:

(1) Total metered output of generation connected to the Company Metering Domain
(2) Plus net imports into the Company Metering Domain
(3) Less net exports from the Company Metering Domain
(4) Less non-retail loads (e.g. wholesale load served to municipalities)
(5) Less the Company Metering Domain's low voltage PTF losses as estimated by ISO-NE.

(b) Determination of Customer Load

The Customer hourly loads shall be determined from either actual hourly interval data or estimated from rate class profiles.

When utilizing average rate class profiles, the Company shall calculate the usage factor for each Customer that reflects the Customer's usage relative to the average usage for the rate class. This Customer usage factor shall be used to scale the class load profile when estimating the Customer's hourly load.

The Company will increase the hourly loads by a distribution loss factor, to account for losses between the Customer meter and the ISO-NE reporting point, the PTF boundary. The distribution loss factors used are for approximation purposes only and are to be used exclusively for the calculation of the Customers loads. Any potential difference between these loss factors and actual hourly losses will be captured in the allocation of residual, as described below.

(c) Determination of Supplier Loads

Each Customer, including those on Default Energy Service or Self-Supply, will be assigned their associated Supplier code from the billing database. The Customer loads from Section (b) above will be summed, for each hour, by this Supplier code. For each hour, the difference between the Retail Territory Load and the sum of the loads from Section (b) above will constitute the "residual". The loads from Section (b) above will be adjusted by the residual. The residual will be allocated proportionally to each Supplier's share of the profiled loads from Section (b) above.

The sum of the loads plus any residual will constitute the Supplier hourly loads. The sum of the Supplier hourly loads in a Metering Domain will equal the Retail Territory Load of the same Metering Domain.

To refine the estimates of the Supplier's loads that result from the estimated hourly loads, a monthly calculation shall be performed to incorporate the most recent Customer usage information, which is available after the monthly meter readings are processed.

(d) Reporting of Supplier Loads for the ISO-NE Settlement Processes

In accordance with the ISO-NE rules and procedures, as amended from time to time, the Company will report to ISO-NE the Supplier hourly loads in the time period specified by the ISO-NE Rules for the initial settlement.

Subsequently, in accordance with the ISO-NE's rules and procedures that pertain to the resettlement processes, the Company will submit to ISO-NE any revised hourly values for assets reflected in the ISO-NE settlement system that are used to determine the Retail Territory Load for each hour of each day. The Company will also submit to ISO-NE any revised hourly energy quantities for each Supplier for each resettlement process.

As wholesale electricity market changes are implemented, the Company will comply with all such applicable market changes when determining the Retail Territory Load. The Company also shall determine and report the Supplier loads consistent with applicable market rules and procedures.

(e) Data Review

The process of Supplier load estimation involves statistical samples and estimating error. The Company shall not be responsible for any estimating reporting, settlement or other types of errors associated with, or resulting from, this process, and the Company shall not be liable to any Supplier or any third party for any costs or losses that are associated with such errors. Each Supplier is solely responsible for checking and ensuring the accuracy of all such data.

The terms above are also applicable to Customers who are receiving Self-Supply Service.

8. Liability

The Company shall have no liability with respect to any transaction or arrangement by or between a Customer and Supplier.

The Company and the Supplier shall indemnify and hold the other and their respective affiliates, and the directors, officers, employees, and agents of each of them (collectively, "Affiliates") harmless from and against any and all damages, costs (including attorneys' fees), fines, penalties, and liabilities, in tort, contract, or otherwise (collectively, "Liabilities"), resulting from claims of third parties arising, or claimed to have arisen, from the acts or omissions of such party in connection with the performance of its obligations under this Tariff. The Company and the Supplier shall waive recourse against the other party and its Affiliates for or arising from the non-negligent performance by such other party in connection with the performance of its obligations under this Tariff.

RESIDENTIAL DELIVERY SERVICE RATE R

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for Delivery Service in individual urban, rural and farm residences and apartments. Service under this rate is available to those Customers who receive all of their electric service requirements hereunder, except that controlled electric service for thermal storage devices is available under Load Controlled Delivery Service Rate LCS and outdoor area lighting is available under Outdoor Lighting Delivery Service Rate OL.

This rate is not applicable to commercial purposes except as specified hereafter. Multiple use of Delivery Service within the residence through one meter shall be billed in accordance with the predominant use of the demand. When wired for connection to the same meter, Delivery Service under this rate shall include the residence and connecting and adjacent buildings used exclusively for noncommercial purposes.

The use of single-phase motors of 3 H.P. rating or less is permitted under this rate provided such use does not interfere with the quality of service rendered to other Customers. Upon written application to the Company, the use of larger motors may be authorized where existing distribution facilities permit.

CHARACTER OF SERVICE

Delivery Service supplied under this rate will be single-phase, 60 hertz, alternating current, normally three-wire at a nominal voltage of 120/240 volts.

RATE PER MONTH

Customer Charge .... $13.81 per month

Energy Charges:

	Per Kilowatt-Hour
Distribution Charge...	4.811¢
Regulatory Reconciliation Adjustment……….	X.XX¢
Transmission Charge	3.011¢
Stranded Cost Recovery.............................. …	0.982¢

Issued: October 9, 2020 Issued by: /s/ Joseph A. Purington
Joseph A. Purington

Effective: January 1, 2021 Title: President, NH Electric Operations

WATER HEATING - UNCONTROLLED

Uncontrolled water heating service is available under this rate at those locations which were receiving service hereunder on July 1, 2020 and which have continuously received such service since that date, and when such service is supplied to approved water heaters equipped with either (a) two thermostatically-operated heating elements, each with a rating of no more than 5,500 watts, so connected or interlocked that they cannot operate simultaneously, or (b) a single thermostatically-operated heating element with a rating of no more than 5,500 watts. The heating elements or element shall be connected by means of an approved circuit to a separate water heating meter. Delivery Service measured by this meter will be billed monthly as follows:

Meter Charge .... $4.87 per month

Energy Charges:

Distribution Charge……………………….. 2.161¢ per kilowatt-hour
Regulatory Reconciliation Adjustment……….X.XX¢ per kilowatt-hour
Transmission Charge……………………… 2.331¢ per kilowatt-hour
Stranded Cost Recovery…………………… 0.982¢ per kilowatt-hour

WATER HEATING - CONTROLLED

Controlled off-peak water heating is available under this rate for a limited period of time at those locations which were receiving controlled off-peak water heating service hereunder on Customer Choice Date and which have continuously received such service hereunder since that date. Service under this rate at such locations shall continue to be available only for the remaining life of the presently-installed water heating equipment. No replacement water heaters shall be permitted to be installed for service under this rate at locations which otherwise would qualify for this service.

For those locations which qualify under the preceding paragraph, controlled off-peak water heating service is available under this rate when such service is supplied to approved storage type electric water heaters having an off-peak heating element with a rating of no more than 1,000 watts, or 20 watts per gallon of tank capacity, whichever is greater. The off-peak element shall be connected by means of an approved circuit to a separate water heating meter. Electricity used will be billed monthly as follows:

Meter Charge .... $6.38 per month

Energy Charges:

Distribution Charge......................………… 1.141¢ per kilowatt-hour
Regulatory Reconciliation Adjustment……….X.XX¢ per kilowatt-hour
Transmission Charge ....………… 2.331¢ per kilowatt-hour
Stranded Cost Recovery...............………… 0.568¢ per kilowatt-hour

ELDERLY CUSTOMER DISCOUNT

Eligible Customers may receive an Elderly Customer Discount of ten percent (10%) from bill amounts computed under this rate for service rendered at their principal residence.

Eligible Customers are those Customers 70 years of age or older who are owners or renters of their principal residence or who normally pay a substantial portion of the cost of maintaining their principal residence who were receiving the Elderly Customer Discount pursuant to an applicable rate on February 1, 1982, and who have continuously received the Elderly Customer Discount since that date; provided that when an eligible Customer who has been receiving the discount deceases, a surviving spouse who would otherwise be eligible for the discount will be deemed to be an eligible Customer.

The covered provisions of this rate shall include all provisions relating to rates and charges (including the Customer charge and any meter charge) except for charges under the provision entitled "Service Charge", line extension surcharges, or any charges under Default Service. The covered provisions shall also include service under Load Controlled Delivery Service Rate LCS.

SERVICE CHARGE

When the Company establishes or re-establishes a Delivery Service account for a Customer at a meter location, the Company will be entitled to assess a service charge in addition to all other charges under this rate. The service charge will be $10.00 if the Company does not have to send an employee to the meter location to establish or re-establish Delivery Service. When it is necessary for the Company to send an employee to the meter location to establish or re-establish Delivery Service, the service charge will be $35.00. When it is necessary for the Company to send an employee to the meter location outside of normal working hours to establish or re-establish Delivery Service, the service charge will be $80.00. The Company will be entitled to assess an $26.00 service charge when it is necessary to send an employee to the Customer location to collect a delinquent bill. This charge shall apply regardless of any action taken by the Company including accepting a payment, making a deferred payment arrangement or leaving a collection notice at the Customer’s premises.

RESIDENTIAL TIME-OF-DAY DELIVERY SERVICE RATE R-OTOD

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for Delivery Service in individual urban, rural and farm residences and apartments. Service under this rate is available at the Customer's option to those Customers who have completed a written Application for Service and signed a Service Agreement and who receive all of their Delivery Service requirements hereunder, except that outdoor area lighting is available under Outdoor Lighting Delivery Service Rate OL.

This rate is not applicable to commercial purposes except as specified hereafter. Multiple use of service within the residence through one meter shall be billed in accordance with the predominant use of the demand. When wired for connection to the same meter, service under this rate shall include the residence and connecting and adjacent buildings used exclusively for noncommercial purposes.

The use of single-phase motors of 3 H.P. rating or less is permitted under this rate provided such use does not interfere with the quality of service rendered to other Customers. Upon written application to the Company, the use of larger motors may be authorized where existing distribution facilities permit.

LIMITATIONS ON AVAILABILITY

The availability of this rate to particular Customers is contingent upon the availability of time-of-use meters and personnel to administer the rate, all as determined by the Company.

Because the Company's distribution system and Customer service facilities have a limited electrical capacity, large and/or intermittent and irregular electrical loads can result in the overloading and damaging of said facilities and can adversely affect the quality of service to other Customers of the Company. Therefore, service under this rate shall not be available where, in the Company's judgment, sufficient distribution system capacity and Customer service facilities do not exist in order to supply the electrical requirements of the applicant unless the Service Agreement provides for a suitable cash payment or a satisfactory revenue guarantee to the Company, or both. Further, in the event that a Customer receiving service under this rate shall propose to materially increase the amount of Delivery Service required, the Customer shall give the Company prior written notice of this fact, thereby allowing the Company to ascertain whether sufficient distribution system capacity and Customer service facilities exist to serve the proposed increased requirement. Where the capacity or facilities do not exist, the Customer will not make the proposed increase until the Service Agreement shall be amended to provide for a suitable cash payment or a satisfactory revenue guarantee to the Company, or both.

SERVICE AGREEMENT

The term of the Service Agreement shall be one year, and shall continue thereafter until canceled by one month's notice to the Company by the Customer. The Customer will not be permitted to change from this rate to any other rate until the Customer has taken service under this rate for at least twelve months. However, upon payment by the Customer of a suitable termination charge, the Company may, at its option, waive this provision where a substantial hardship to the Customer would otherwise result.

CHARACTER OF SERVICE

Service supplied under this rate will be single-phase, 60 hertz, alternating current, normally three-wire at a nominal voltage of 120/240 volts.

RATE PER MONTH

Customer Charge ....$32.08 per month

Energy Charges:

Per Kilowatt-Hour

Distribution Charges:

On-Peak Hours (7:00 a.m. to 8:00 p.m.
weekdays excluding Holidays) ....14.710¢

Off-Peak Hours (all other hours) ....0.513¢

Regulatory Reconciliation Adjustment……….X.XX¢ per kilowatt-hour

Transmission Charges:

On-Peak Hours (7:00 a.m. to 8:00 p.m.
weekdays excluding Holidays) .... 3.011¢

Off-Peak Hours (all other hours) ....1.966¢

Stranded Cost Recovery..0.844¢

The On-Peak Hours shall be the hours after 7:00 a.m. and before 8:00 p.m. weekdays excluding holidays as defined in this Tariff. The Off-Peak Hours shall be all hours not included in the On-Peak Hours.

CAPACITY CHARGE

The Company's studies may show that, in order to more closely follow cost of service, it is necessary or desirable to utilize meters capable of measuring rate of taking of electric service in kilowatts. The Company may install such meters either for all Customers served under this rate or for only those Customers whose usage of electricity is uncharacteristic of this class. At any time, the Company may file a revision of the rate form and/or charges of this rate to provide for an appropriate capacity charge. After such revision of this rate, any Customer who is subject to higher billing under this rate will have the option of continuing to take service under this rate or to take service under any other rate of the Company's Tariff which may be available.

WATER HEATING - UNCONTROLLED

Uncontrolled water heating service is available at those locations which were receiving service hereunder on July 1, 2020 and which have continuously received such service since that date, and when such service is supplied to approved water heaters equipped with either (a) two thermostatically-operated heating elements, each with a rating of no more than 5,500 watts, so connected or interlocked that they cannot operate simultaneously, or (b) a single thermostatically-operated heating element with a rating of no more than 5,500 watts. The heating elements or element shall be connected by means of an approved circuit to a separate water heating meter.

Delivery Service measured by this meter will be billed monthly as follows:

Meter Charge ....$4.87 per month

Energy Charges:

Distribution Charge............................ 2.161¢ per kilowatt-hour
Distribution Adjustment Charge .... x.xxx¢ per kilowatt-hour
Transmission Charge .... 2.331¢ per kilowatt-hour
Stranded Cost Recovery..................... 0.982¢ per kilowatt-hour

WATER HEATING - CONTROLLED

Controlled off-peak water heating is available under this rate for a limited period of time at those locations which were receiving controlled off-peak water heating service hereunder on Customer Choice Date and which have continuously received such service hereunder since that date. Service under this rate at such locations shall continue to be available only for the remaining life of the presently-installed water heating equipment. No replacement water heaters shall be permitted to be installed for service under this rate at locations which otherwise would qualify for this service.

For those locations which qualify under the preceding paragraph, controlled off-peak water heating service is available under this rate when such service is supplied to approved storage type electric water heaters having an off-peak heating element with a rating of no more than 1,000 watts, or 20 watts per gallon of tank capacity, whichever is greater. The off-peak element shall be connected by means of an approved circuit to a separate water heating meter. Electricity used will be billed monthly as follows:

Meter Charge .... $6.38 per month

Energy Charges:

Distribution Charge...........................……… 1.141¢ per kilowatt-hour

Regulatory Reconciliation Adjustment X.XX¢ per kilowatt-hour

Transmission Charge ....……… 2.331¢ per kilowatt-hour

Stranded Cost Recovery…………………….0.568¢ per kilowatt-hour

SERVICE CHARGE

When the Company establishes or re-establishes a Delivery Service account for a Customer at a meter location, the Company will be entitled to assess a service charge in addition to all other charges under this rate. The service charge will be $10.00 if the Company does not have to send an employee to the meter location to establish or re-establish Delivery Service. When it is necessary for the Company to send an employee to the meter location to establish or re-establish Delivery Service, the service charge will be $35.00. When it is necessary for the Company to send an employee to the meter location outside of normal working hours to establish or re-establish Delivery Service, the service charge will be $80.00. The Company will be entitled to assess an $26.00 service charge when it is necessary to send an employee to the Customer location to collect a delinquent bill. This charge shall apply regardless of any action taken by the Company including accepting a payment, making a deferred payment arrangement or leaving a collection notice at the Customer's premises.

RESIDENTIAL ELECTRIC ASSISTANCE PROGRAM RATE EAP

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is available to the primary residence of residential Customers with a household income equal to or less than 200% of the federal poverty guidelines subject to the availability of funds for this program. Customers may apply for this rate with the Electric Assistance Program Administrator (Administrator) designated by the Public Utilities Commission. The Administrator will determine initial eligibility for Rate EAP and the appropriate Percent Discount level. The Administrator will also re-certify each Customer on or before the expiration date of the Customer's certification period. Billing for service under this rate shall commence on the date of the Customer's next meter read date (Effective Date) following the receipt by the Company of a certification notification transaction from the Administrator. Service under this rate shall continue until the Company receives a removal notification transaction from the Administrator, except that in the event the Customer terminates Delivery Service and does not request Delivery Service within 30 days, the Company may immediately remove the Customer from the Electric Assistance Program without notice to the Customer.

This rate is available in conjunction with the Company's Residential Delivery Service Rate R or Residential Time-of-Day Delivery Service Rate R-OTOD. Therefore, service shall be provided in accordance with the terms and conditions of Rate R or Rate R-OTOD as now or hereafter effective, except as specifically provided otherwise in this rate.

PERCENT DISCOUNT

For Customers receiving energy service under Default Energy Service, Customers will be billed for Delivery Service under Residential Delivery Service Rate R or Residential Time-of-Day Delivery Service Rate R-OTOD and for Default Energy Service, except that a Percent Discount will be applied to all applicable Delivery Service and Default Energy Service rate charges which includes the Customer Charge, any Meter Charge, the Distribution Charge, the Regulatory Reconciliation Adjustment, the Transmission Charge, the Stranded Cost Recovery Charge, the System Benefits Charge and the Default Energy Service Charge for the first 750 kWh of monthly usage per service account. The Percent Discount will not be applied to the Line Extension Surcharges, Returned Check Charges or Service Charges. The Percent Discount cannot be applied to or combined with the Elderly Customer Discount. The covered provisions of this rate shall also include service under Load Controlled Delivery Service Rate LCS.

For Customers receiving energy service from an Energy Service Provider that has elected to receive Billing and Payment Service from the Company (otherwise known as consolidated billing), the Percent Discount will be calculated in the same manner as Customers receiving energy service under Default Energy Service, i.e. the Company's Default Energy Service rate will be used in the calculation of the discount, rather than the Energy Service Provider's rate, regardless of the difference in rates. All other Percent Discount provisions remain the same as those applicable to Customers receiving energy service under Default Energy Service including the application of the Percent Discount to the first 750 kWh of monthly usage per service account.

The following percent discounts apply:

Tier	Percentage of Federal Poverty Guidelines	Discount
2	151% to 200%	8%
3	126% to 150%	22%
4	101% to 125%	36%
5	76% to 100%	52%
6	up to 75%	76%

DEPOSITS

Deposits obtained by the Company prior to the Effective Date of service under this rate plus interest accrued thereon due to four consecutive disconnect notices, disconnection of service, or failure to provide satisfactory evidence of intent to remain at the service location for a period of twelve consecutive months shall be reviewed to ensure that the deposit amount plus accrued interest does not exceed the Customer's total bill for two high use months. To the extent the deposit exceeds the total bill amount of two high use months discounted by the Percent Discount the customer will receive on future bills under this rate, the difference shall be first applied to any outstanding balance owed to the Company by the Customer after the crediting of qualifying pre-program past due balances. Any remaining difference shall be refunded to the Customer within two months following the Effective Date of service under this rate. All other deposits obtained by the Company prior to the Effective Date of service under this rate shall be first applied to any outstanding balance owed to the Company by the Customer after the crediting of qualifying pre-program past due balances. Any remaining deposit amount shall be refunded to the Customer within two months following the Effective Date of service under this rate.

When deposits are required from Customers receiving service under this rate, the deposit shall not be more than the estimated bill for Delivery Service and Energy Service, if applicable, for a period of two high use months reduced by the amount of the Percent Discount when those months were incurred prior to the Effective Date of service under this rate.

GENERAL DELIVERY SERVICE RATE G

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for Delivery Service for any use. It is available to (1) those Customers at existing delivery points who were receiving service hereunder on General Service Rate G on January 1, 1983, and who have continuously received service under that rate and this successor since that date, and (2) all other Customers whose loads as defined for billing purposes do not exceed 100 kilowatts. Service rendered hereunder shall exclude all backup and standby service provided under Backup Delivery Service Rate B.

Customers taking service under this rate shall provide any necessary transforming and regulating devices on the Customer's side of the meter. Controlled electric service for thermal storage devices is available under Load Controlled Service Rate LCS and outdoor area lighting is available under Outdoor Lighting Delivery Service Rate OL.

CHARACTER OF SERVICE

Delivery Service supplied under this rate will be 60 hertz, alternating current, either (a) single-phase, normally three-wire at a nominal voltage of 120/240 volts, or (b) three-phase, normally at a nominal voltage of 120/208 or 277/480 volts. Three-phase, three-wire service at a nominal voltage of 240, 480 or 600 volts is available only to those Customers at existing locations who were receiving such service on February 1, 1986, and who have continuously received such service since that date. In underground secondary network areas, Delivery Service will be supplied only at a nominal voltage of 120/208 volts.

RATE PER MONTH

	Single-Phase Service	Three-Phase Service
Customer Charge	$16.21 per month	$32.39 per month

Customer's Load Charges:

	Per Kilowatt of Customer Load in Excess of 5.0 Kilowatts
Distribution Charge	$10.49
Regulatory Reconciliation Adjustment	$X.XX
Transmission Charge	$7.77
Stranded Cost Recovery	$0.69

Issued: October 9, 2020

Issued by: /s/ Joseph A. Purington
Joseph A. Purington

Effective: January 1, 2021

Title: President, NH Electric Operations

Energy Charges:

Per Kilowatt-Hour

Distribution Charges:

First 500 kilowatt-hours..2.805¢

Next 1,000 kilowatt-hours ....2.268¢

All additional kilowatt-hours ....1.709¢

Transmission Charge

First 500 kilowatt-hours..2.807¢

Next 1,000 kilowatt-hours ....1.056¢

All additional kilowatt-hours ....0.566¢

Stranded Cost Recovery..0.732¢

WATER HEATING - UNCONTROLLED

Uncontrolled water heating service is available under this rate at those locations which were receiving service hereunder on July 1, 2020 and which have continuously received such service since that date, and when such service is supplied to approved water heaters equipped with either (a) two thermostatically-operated heating elements, each with a rating of no more than 5,500 watts, so connected or interlocked that they cannot operate simultaneously, or (b) a single thermostatically-operated heating element with a rating of no more than 5,500 watts. The heating elements or element shall be connected by means of an approved circuit to a separate water heating meter. Service measured by this meter will be billed monthly as follows:

Meter Charge .... $4.87 per month

Energy Charges:

Distribution Charge......................... 2.161¢ per kilowatt-hour

Regulatory Reconciliation Adj. ......X.XX¢ per kilowatt-hour

Transmission Charge .... 2.331¢ per kilowatt-hour

Stranded Cost Recovery.................. 0.924¢ per kilowatt-hour

WATER HEATING - CONTROLLED

Controlled off-peak water heating is available under this rate for a limited period of time at those locations which were receiving controlled off-peak water heating service hereunder on Customer Choice Date and which have continuously received such service hereunder since that date. Service under this rate at such locations shall continue to be available only for the remaining life of the presently-installed water heating equipment. No replacement water heaters shall be permitted to be installed for service under this rate at locations which otherwise would qualify for this service.

For those locations which qualify under the preceding paragraph, controlled off-peak water heating service is available under this rate when such service is supplied to approved storage type electric water heaters having an off-peak heating element with a rating of no more than 1,000 watts, or 20 watts per gallon of tank capacity, whichever is greater. The off-peak element shall be connected by means of an approved circuit to a separate water heating meter. Electricity used will be billed monthly as follows:

Meter Charge ....$6.38 per month

Energy Charges:

Distribution Charge............................ 1.141¢ per kilowatt-hour

Regulatory Reconciliation Adj. .... X.XX¢ per kilowatt hour

Transmission Charge .... 2.331¢ per kilowatt-hour

Stranded Cost Recovery..................... 0.532¢ per kilowatt-hour

SPACE HEATING SERVICE

Space heating service is available under this rate at those locations which were receiving space heating service under the Transitional Space Heating Service Rate TSH prior to Customer Choice Date and which have continuously received such service since that date. Customers at such locations who have elected this rate shall have the electricity for such service billed separately on a monthly basis as follows:

Meter Charge ....$3.24 per month

Energy Charges:

Distribution Charge............................ 3.908¢ per kilowatt-hour

Transmission Charge .... 2.807¢ per kilowatt-hour

Stranded Cost Recovery..................... 1.159¢ per kilowatt-hour

Space heating equipment served under this rate, including heat pumps and associated air circulating equipment, shall be wired by means of approved circuits to permit measurement of such equipment's additional demand and energy use.

Customers taking space heating service under this rate at locations where the regular power and lighting service is delivered at primary voltage level or above shall be required to provide at the Customers' expense suitable transforming, controlling and regulating apparatus, acceptable to and approved by the Company, for the space heating service in the same manner as for the power and lighting service, so that deliveries of all electric service may be made by the Company at the same voltage level.

CUSTOMER'S LOAD

Customer's load is defined as the greatest rate of taking Delivery Service in kilowatts for any thirty (30) minute interval during the current monthly billing period.

Customer's load shall be measured whenever (a) such load is known or estimated to be 5.0 kilowatts or more, or (b) the Customer's use of service is 750 kilowatt-hours or more per month for three (3) consecutive months. However, any Customer's load may be measured at the Company's option. When measured, Customer's load shall be determined to the nearest one-tenth (0.1) kilowatt for billing purposes.

SERVICE CHARGE

When the Company establishes or re-establishes a Delivery Service account for a Customer at a meter location, the Company will be entitled to assess a service charge in addition to all other charges under this rate. The service charge will be $10.00 if the Company does not have to send an employee to the meter location to establish or re-establish Delivery Service. When it is necessary for the Company to send an employee to the meter location to establish or re-establish Delivery Service, the service charge will be $35.00. When it is necessary for the Company to send an employee to the meter location outside of normal working hours to establish or re-establish Delivery Service, the service charge will be $80.00. The Company will be entitled to assess an $26.00 service charge when it is necessary to send an employee to the Customer location to collect a delinquent bill. This charge shall apply regardless of any action taken by the Company including accepting a payment, making a deferred payment arrangement or leaving a collection notice at the Customer’s premises.

Short-term, seasonal or transient Customers who take service at temporary locations shall pay for the cost of installing and removing the necessary poles, wires, transformers, cable and other equipment in addition to the foregoing service charge.

GENERAL TIME-OF-DAY DELIVERY SERVICE RATE G-OTOD

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for Delivery Service to Customers who utilize electric thermal storage devices and other applications approved by the Company. It is available to Customers whose loads as defined for billing purposes do not exceed 100 kilowatts. Service is available at the Customer's option to those Customers who have completed a written Application for Service and signed a Service Agreement, and who receive all of their Delivery Service requirements hereunder, except that outdoor area lighting is available under Outdoor Lighting Service Rate OL.

Customers taking service under this rate shall provide any necessary transforming and regulating devices on the Customer's side of the meter.

LIMITATIONS ON AVAILABILITY

The availability of this rate to particular Customers is contingent upon the availability of time-of-use meters and personnel to administer the rate, all as determined by the Company.

Because the Company's distribution system and Customer service facilities have a limited electrical capacity, large and/or intermittent and irregular electrical loads can result in the overloading and damaging of said facilities and can adversely affect the quality of service to other Customers of the Company. Therefore, service under this rate shall not be available where, in the Company's judgment, sufficient distribution system capacity and Customer service facilities do not exist in order to supply the electrical requirements of the applicant unless the Service Agreement provides for a suitable cash payment or a satisfactory revenue guarantee to the Company, or both. Further, in the event that a Customer receiving service under this rate shall propose to materially increase the amount of Delivery Service required, the Customer shall give the Company prior written notice of this fact, thereby allowing the Company to ascertain whether sufficient distribution system capacity and Customer service facilities exist to serve the proposed increased requirement. Where the capacity or facilities do not exist, the Customer will not make the proposed increase until the Service Agreement shall be amended to provide for a suitable cash payment or a satisfactory revenue guarantee to the Company, or both.

SERVICE AGREEMENT

The term of the Service Agreement shall be one year, and shall continue thereafter until canceled by one month's notice to the Company by the Customer. The Customer will not be permitted to change from this rate to any other rate until the Customer has taken service under this rate for at least twelve months. However, upon payment by the Customer of a suitable termination charge, the Company may, at its option, waive this provision where a substantial hardship to the Customer would otherwise result.

CHARACTER OF SERVICE

Service supplied under this rate will be 60 hertz, alternating current, either (a) single-phase, normally three-wire at a nominal voltage of 120/240 volts or (b) three-phase, normally at a nominal voltage of 120/208 or 277/480 volts. Three-phase, three-wire service at a nominal voltage of 240, 480 or 600 volts is available only to those Customers at existing locations who were receiving such service on February 1, 1986, and who have continuously received such service since that date. In underground secondary network areas, service will be supplied only at a nominal voltage of 120/208 volts.

RATE PER MONTH

	Single-Phase Service	Three-Phase Service
Customer Charge	$41.98 per month	$60.00 per month

Customer's Load Charges:

	Per Kilowatt of Customer Load
Distribution Charge	$13.92
Regulatory Reconciliation Adjustment	$X.XX
Transmission Charge	$ 5.12
Stranded Cost Recovery	$ 0.35

Energy Charges:

	Per Kilowatt-Hour
Distribution Charges:	
On-Peak Hours (7:00 a.m. to 8:00 p.m. weekdays excluding Holidays)	5.335¢
Off-Peak Hours (all other hours)	0.836¢
Stranded Cost Recovery	0.532¢

CUSTOMER'S LOAD

Customer's load is defined as the greatest rate of taking service in kilowatts for any thirty (30) minute interval during on-peak hours of the current monthly billing period. On-peak hours shall be the hours of 7:00 a.m. through 8:00 p.m. weekdays excluding Holidays as defined in this Tariff.

SERVICE CHARGE

When the Company establishes or re-establishes a Delivery Service account for a Customer at a meter location, the Company will be entitled to assess a service charge in addition to all other charges under this rate. The service charge will be $10.00 if the Company does not have to send an employee to the meter location to establish or re-establish Delivery Service. When it is necessary for the Company to send an employee to the meter location to establish or re-establish Delivery Service, the service charge will be $35.00. When it is necessary for the Company to send an employee to the meter location outside of normal working hours to establish or re-establish Delivery Service, the service charge will be $80.00. The Company will be entitled to assess an $26.00 service charge when it is necessary to send an employee to the Customer location to collect a delinquent bill. This charge shall apply regardless of any action taken by the Company including accepting a payment, making a deferred payment arrangement or leaving a collection notice at the Customer’s premises.

LOAD CONTROLLED DELIVERY SERVICE RATE LCS

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part and as provided hereinafter, the radio-controlled option of this rate is available at those locations which were receiving service hereunder on July 1, 2020 and which have continuously received such service since that date. Under the radio-controlled option it is applicable to separately metered and controlled Delivery Service to electric thermal storage devices and to conventional electric space heating when a dynamic electric thermal storage system or a wood stove or coal stove is available for use as a backup during times when service is interrupted by the Company and other applications approved by the Company. Service under the 8-hour, 10-hour and 11-hour options is available only at those locations which were receiving service under one of these options under Load Controlled Service Rate LCS or Controlled Off-Peak Electric Water Heating Service Rate COPE on October 1, 2004 and which have continuously received such service since that date.

The availability of the radio-controlled option in conjunction with a wood stove or coal stove shall be limited to those premises which have electric space heating equipment as the sole source of space heating, excluding the wood stove or coal stove. Such wood stove or coal stove must be permanently installed and sized to adequately heat the main living area of the premises.

Service under this rate is available at the Customer's option to those Customers whose electric thermal storage or other equipment has been approved by the Company for load control as provided hereinafter. Such equipment must be connected to a separate circuit to which no other electrical load shall be connected.

Radio-Controlled Option - Delivery service will be subject to interruptions of up to eight (8) hours during each twenty-four (24) hour day between 7:00 a.m. and 11:00 p.m. Each interruption will not exceed four (4) hours and the time between two consecutive interruptions will be no less than two (2) hours.

This rate is intended as a rider applicable to Residential Delivery Service Rate R or General Delivery Service Rate G. Therefore, service under this rate must be taken in conjunction with service provided under either Rate R or Rate G in accordance with the terms and conditions therein as now or hereafter effective except as may be specifically provided otherwise in this rate.

LIMITATIONS ON AVAILABILITY

Service under this rate shall not be available where, in the Company's judgment, sufficient distribution system capacity does not exist in order to supply the electrical requirements of the applicant unless the Customer provides for a suitable cash payment or a satisfactory revenue guarantee to the Company, or both.

The availability of this rate is also contingent upon the availability to the Company of personnel and/or other resources necessary to provide service under this rate.

TERM

The term of service under this rate shall be one year, and shall continue thereafter until canceled by one month's notice to the Company by the Customer. The Customer will not be permitted to change from this rate to any other rate until the Customer has taken service under this rate for at least twelve months. However, upon payment by the Customer of a suitable termination charge, the Company may, at its option, waive this provision where a substantial hardship to the Customer would otherwise result.

RATE PER MONTH

Customer Charges:

Radio-Controlled Option ....$6.99 per month

8-Hour, 10-Hour or 11-Hour Option ....$6.38 per month

Energy Charges:

	Per Kilowatt-Hour
Distribution Charges:	
Radio-Controlled Option or 8-Hour Option	1.141¢
10-Hour or 11-Hour Option	2.161¢
Regulatory Recovery Adjustments:	
Radio-Controlled Option	X.XXX¢
8-Hour Option	X.XXX¢
10-Hour or 11-Hour Option	X.XXX¢
Transmission Charge	2.331¢
Stranded Cost Recovery (When service is taken in conjunction with Rate R)	0.568¢
Stranded Cost Recovery (When service is taken in conjunction with Rate G)	0.532¢

METERS

Under this rate, the Company will install one meter with appropriate load control devices.

ELECTRIC THERMAL STORAGE EQUIPMENT APPROVED FOR LOAD CONTROL

Load Controlled Service is available under this rate to electric thermal storage installations meeting the Company's specifications as to type, size and electrical characteristics in accordance with the following guidelines.

I. Electric Thermal Storage Space Heating Equipment

Adequate control and switching equipment must be installed to provide capability for staggering the commencement of the charging period with respect to other electric thermal storage devices and for permitting partial charging on warmer days, and for controlling service to the thermal storage devices.

The storage capability of the electric thermal storage device must be adequate to heat the Customer's whole premises under design conditions and must be properly sized to ensure

A constant rate of charging during the period which service under this rate is available as determined by the Company in accordance with its customary procedures. A smaller sized electric thermal storage device may be approved by the Company for use in the Customer's premises under the Radio Controlled Option.

II. Electric Thermal Storage Water Heating

Load Controlled Service for electric thermal storage water heating is available under this rate when service is taken in conjunction with electric thermal storage space heating and at those locations which were receiving service under the Controlled Off-Peak Electric Water Heating Service Rate COPE on October 1, 2004 and which have continuously received such service since that date.

Service shall be supplied to electric thermal storage water heaters having either (i) two thermostatically-operated top and bottom heating elements, each with a rating of no more than 4,500 watts or forty (40) watts per gallon of storage capacity, whichever is greater, or (ii) a single thermostatically-operated heating element with a rating of 4,500 watts or forty (40) watts per gallon of storage capacity, whichever is greater. When there are two elements, both top and bottom elements must be connected and wired for Load Controlled Service, and must be connected or interlocked so that they cannot operate simultaneously.

The storage capacity of all electric thermal water heaters installed under the Radio-Controlled Option shall be forty (40) gallons or more. The storage capacity of all electric thermal water heaters installed under the 8-Hour, 10-Hour and 11-Hour Options shall be eighty (80) gallons or more. At the Company's option, smaller tanks may be installed for use in an individual apartment of a multi-family building under the 8-Hour, 10-Hour and 11-Hour Options.

INCREASED WATER HEATING CAPABILITY

Electric thermal storage water heating with switching capabilities for increasing the capability of the Customer's water heating equipment is available under this rate at those locations which had switching capability installed on or before January 1, 1994 and which have continuously received such service since that date. The element or elements must be connected and wired such that increased water heating capability is provided under Rate R or Rate G. Customers with installed switching capability will be billed an additional $1.35 per month as a Customer charge. Switching capability is not available under the Radio-Controlled Option.

FEE FOR EMERGENCY CHARGING

If, due to an electrical outage or equipment malfunction, emergency charging of electric thermal storage devices is required at any time during which Delivery Service under this rate is not normally available, the Company will perform such charging upon sufficient notification. If charging is necessitated as a result of a malfunction of the Customer's equipment, the Company may assess the Customer a fee for such charging.

PRIMARY GENERAL DELIVERY SERVICE RATE GV

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for high voltage Delivery Service. It is available upon the signing of a Service Agreement for such service at specified delivery points to Customers whose maximum demand shall not exceed 1,000 kilowatts. Service rendered hereunder shall exclude backup and standby service provided under Backup Delivery Service Rate B. Outdoor area lighting is available under Outdoor Lighting Delivery Service Rate OL.

Suitable transforming, controlling and regulating apparatus, acceptable to and approved by the Company, shall be provided at the expense of the Customer. In locations in which space limitations or other factors make it impossible or inadvisable, in the opinion of the Company, for the Customer to have transforming apparatus devoted to its exclusive use, and in secondary network areas in which primary service is not made available by the Company at its option, Delivery Service shall be supplied from Company-owned transforming apparatus which also supplies other Customers. In such cases, this rate is available provided the Customer pays an annual rental charge equal to eighteen percent (18.0%) of the cost of the equivalent transformer capacity the Customer would furnish or rent to serve the load if exclusive use of a transformer bank by him were possible or if primary, three-phase service were available and provided the Customer pays in full the estimated cost of installing such equivalent transformer capacity at the time Delivery Service is initiated.

CHARACTER OF SERVICE

Delivery Service supplied under this rate will be three-phase, 60 hertz, alternating current, at a nominal voltage determined by the Company, generally 2,400/4,160, 4,800/8,320, 7,200/12,470, or 19,920/34,500 volts. A reasonably balanced load between phases shall be maintained by the Customer.

RATE PER MONTH

Customer Charge ....$211.21 per month

Demand Charges:

Per Kilowatt of Maximum Demand

Distribution Charges:

First 100 kilowatts.. $6.48

Excess Over 100 kilowatts..................................... $6.22

Regulatory Reconciliation Adjustment....................................$X.XX

Transmission Charge $10.40

Stranded Cost Recovery... $0.65

Energy Charges:

Per Kilowatt-Hour

Distribution Charges:

First 200,000 kilowatt-hours...................................0.657¢

All additional kilowatt-hours ....0.583¢

Stranded Cost Recovery…………………………………….. 0.643¢

Issued: October 9, 2020

Issued by: /s/ Joseph A. Purington
Joseph A. Purington

Effective: January 1, 2021

Title: President, NH Electric Operations

PRIMARY METERING LOSS ADJUSTMENT

When at the Company's option Delivery Service is metered at delivery voltage (2,400 volts nominal and above), all demand and energy meter readings shall be reduced by one and three-quarters percent (1.75%). Where feasible and at the Company's option, a value other than one and three-quarters percent (1.75%) may be used when specific data is available and this value is a more accurate representation of electrical losses.

MAXIMUM DEMAND

The kilowatt (KW) demand and, at the Company's option, the kilovolt-ampere (KVA) demand during each thirty-minute interval of the current monthly billing period shall be determined by measurement. Maximum demand shall be determined to the nearest whole (1.0) kilowatt (KW) or kilovolt-ampere (KVA) for billing purposes and shall be defined as the greater of:

(1) the highest kilowatt (KW) demand registered during the on-peak hours of said period or if kilovolt-ampere (KVA) demand is measured, the greater of (a) the highest kilowatt (KW) demand during said period or, (b) 80 percent of the highest kilovolt-ampere (KVA) demand measured of said period or,

(2) fifty percent (50%) of the maximum demand, as defined above, occurring during off-peak hours.

OFF-PEAK PERIODS

The off-peak period shall be the period including the hours after 8:00 p.m. and before 7:00 a.m. Monday through Friday, and the entire day on Saturdays, Sundays, and Holidays as defined in this Tariff. The on-peak period shall be all hours not included in the off-peak period.

CONTRACT TERM

The contract term shall be for not less than one year and for such longer periods as maybe determined by the operation of the sections in this rate entitled “Guarantees” and “Apparatus”.

GUARANTEES

(a) When the estimated expenditure necessary to deliver electrical energy properly to a Customer's premises shall be of such an amount that the income to be derived from the delivery of such energy at the rate herein established, including the monthly minimum charge, will be insufficient to warrant such expenditure, the Company may require the Customer to guarantee a minimum annual payment for a term of years and/or to pay the whole or a part of the cost of extending, enlarging, or rebuilding its facilities to supply the Customer's premises or other reasonable payments in addition to the payments otherwise provided herein.

(b) Except as provided by the Terms and Conditions and as modified by the provisions of Paragraph (a) of this section, and exclusive of any charges made under the provisions of the section in this rate entitled "Apparatus" and if applicable, for Default Energy Service, the minimum charge shall be $1,015 per month.

APPARATUS

Substation foundations, structures, and all necessary controlling, regulating, transforming, and protective apparatus shall be furnished, owned, and maintained by the Customer at the Customer’s expense. However, controlling, regulating, and transforming apparatus may be rented from the Company at a charge of eighteen percent (18.0%) per year of the equipment cost. The cost of installing such equipment shall be paid in full at the time service is initiated. In no event shall the Company be required to rent apparatus to the Customer the total cost of which shall exceed $10,000. The Company may refuse to rent pole-mounted apparatus based on environmental and other immediate hazards that are present. In the event the Company refuses to rent a pole-mounted apparatus, the Company shall inform the Customer of the environmental and other immediate hazards that are present and shall provide the Customer with the opportunity to remove the hazards. In the event the environmental and the other immediate hazards are removed by the Customer, the Company shall agree to rent pole-mounted apparatus to the Customer. If a Customer-owned structure supporting a Company owned pole-mounted transformer is deemed insufficient or threatened by trees or other hazards, the Company shall inform the Customer of the hazards and shall provide the Customer with the opportunity to repair or remove the hazard. In the event the Customer refuses to repair or remove the hazard or does not repair or remove the hazard in a timely manner, the Company is authorized to terminate the existing rental agreement and to remove the transformer upon 90 days written notice to the Customer. In cases where the Customer elects to rent apparatus from the Company, the Customer shall guarantee, in addition to any other guarantees, to continue to pay rental therefor for a period of not less than four (4) years. Should the Customer discontinue service before four (4) years shall have elapsed, the guaranteed rental then unpaid shall immediately become due and payable.

METERING

The Company may install one or more meters at its option. Metering shall be located on the low voltage side of the Customer's transforming apparatus provided, however, that metering may be at delivery voltage at the option of the Company.

LARGE GENERAL DELIVERY SERVICE RATE LG

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for high voltage Delivery Service. It is available upon the signing of a Service Agreement for such service at specified delivery points to Customers whose loads are larger than those that would be permitted under Rate GV of this Tariff. Service rendered hereunder shall exclude all backup and standby service provided under Backup Delivery Service Rate B. Outdoor area lighting is available under Outdoor Lighting Delivery Service Rate OL. Substation foundations and structures, and suitable controlling, regulating, and transforming apparatus, all of which shall be acceptable to and approved by the Company, together with such protective equipment as the Company shall deem necessary for the protection and safe operation of its system, shall be provided at the expense of the Customer.

CHARACTER OF SERVICE

Delivery Service supplied under this rate will be three-phase, 60 hertz, alternating current, at a nominal delivery voltage determined by the Company, generally 34,500 volts or higher. A reasonably balanced load between phases shall be maintained by the Customer.

RATE PER MONTH

Customer Charge .... $660.15 per month

Demand Charges:

Per Kilovolt-Ampere of Maximum Demand

Distribution Charge.. $5.51

Regulatory Reconciliation Adjustment.................................. $X.XX

Transmission Charge $10.24

Stranded Cost Recovery... $0.49

Energy Charges:

Per Kilowatt-Hour

Distribution Charges:

On-Peak Hours..0.554¢

Off-Peak Hours ....0.468¢

Issued: October 9, 2020 — Issued by: /s/ Joseph A. Purington
Joseph A. Purington

Effective: January 1, 2021 — Title: President, NH Electric Operations

Energy Charges (Continued...)

	Per Kilowatt-Hour
Stranded Cost Recovery:	
On-Peak Hours	0.519¢
Off-Peak Hours	0.378¢

MAXIMUM DEMAND

The kilovolt-ampere (KVA) demand during each thirty-minute interval of the current monthly billing period shall be determined by measurement. Maximum demand shall be determined for billing purposes to the nearest whole (1.0) kilovolt-ampere and shall be defined as the greater of:

(1) the highest kilovolt-ampere demand registered during the on-peak hours of said period, or

(2) fifty percent (50%) of the highest kilovolt-ampere demand registered during the off-peak hours of said period, except that for any portion of the Customer's highest off-peak kilovolt-ampere demand in excess of 30,000 kilovolt-amperes the multiplier applicable to the amount of such demand within each successive 10,000 kilovolt-ampere block of such excess portion shall be increased from fifty percent (50%) by successive ten percent (10%) increments, up to a maximum multiplier of one hundred percent (100%) for that portion of demand in excess of 70,000 kilovolt amperes, or

(3) eighty percent (80%) of the amount by which the greatest amount defined in (1) and (2) above during the eleven (11) preceding months exceeds 1,000 kilovolt-amperes.

OFF-PEAK PERIOD

The off-peak period shall be the period including the hours after 8:00 p.m. and before 7:00 a.m., Monday through Friday, and the entire day on Saturdays, Sundays, and Holidays. The on-peak period shall be all hours not included in the off-peak period.

CONTRACT TERM

The contract term shall be for not less than one year and for such longer periods as maybe determined by the operation of the sections in this rate entitled “Guarantees” and “Apparatus”.

DISCOUNT FOR SERVICE AT 115,000 VOLTS

A monthly discount of forty-nine cents ($0.49) per kilovolt-ampere (KVA) of maximum demand shall be given to Customers who contract to take service under this rate at a delivery voltage of 115,000 volts and to pay charges based on a monthly maximum demand of at least 10,000 kilovolt-amperes. Except as provided in the last sentence of this paragraph, this discount is available only at specified delivery points on the 115,000 volt transmission system of the Company as it exists from time to time where, in the opinion of the Company, there is sufficient capacity in facilities to supply the Customer's requirement and where system integrity and operating flexibility will not be impaired by the addition of the Customer's load. The discount is available also at other delivery points, provided the Customer satisfies the Company's requirements determined under Paragraph (a) of the section of this rate entitled "Guarantees".

In the event that any Customer qualifying for and receiving the discount provided in this section shall require a substantially larger or substantially smaller amount of capacity, the Customer shall so notify the Company in writing at least two (2) years prior to the date when such larger or smaller amount shall be required.

GUARANTEES

(a) When the estimated expenditure necessary to deliver electrical energy properly to a Customer's premises shall be of such an amount that the income to be derived from the delivery of such energy at the rate herein established, including the monthly minimum charge, will be insufficient to warrant such expenditure, the Company may require the Customer to guarantee a minimum annual payment for a term of years and/or to pay the whole or a part of the cost of extending, enlarging, or rebuilding its facilities to deliver electrical energy properly to the Customer's point of delivery or other reasonable payments in addition to the payments otherwise provided herein.

(b) Except as provided by the Terms and Conditions and as modified by the provisions of Paragraph (a) of this section, and exclusive of any charges made under the provisions of the section in this rate entitled "Apparatus" and if applicable, for Default Energy Service, the minimum monthly charge shall be $1,076 per month.

APPARATUS

Substation foundations, structures, and all necessary controlling, regulating, transforming, and protective apparatus shall be furnished, owned, and maintained by the Customer at the Customer's expense. However, controlling, regulating, and transforming apparatus may be rented from the Company at a charge of eighteen percent (18.0%) per year of the equipment cost. The cost of installing such equipment shall be paid in full at the time service is initiated. In no event shall the Company be required to rent apparatus to the Customer the total cost of which shall exceed $10,000. The Company may refuse to rent pole-mounted apparatus based on environmental and other immediate hazards that are present. In the event the Company refuses to rent a pole-mounted apparatus, the Company shall inform the Customer of the environmental and other immediate hazards that are present and shall provide the Customer with the opportunity to remove the hazards. In the event the environmental and the other immediate hazards are removed by the Customer, the Company shall agree to rent pole-mounted apparatus to the Customer. If a Customer-owned structure supporting a Company owned pole-mounted transformer is deemed insufficient or threatened by trees or other hazards, the Company shall inform the Customer of the hazards and shall provide the Customer with the opportunity to repair or remove the hazard. In the event the Customer refuses to repair or remove the hazard or does not repair or remove the hazard in a timely manner, the Company is authorized to terminate the existing rental agreement and to remove the transformer upon 90 days written notice to the Customer. In cases where the Customer elects to rent apparatus from the Company, the Customer shall guarantee, in addition to any other guarantees, to continue to pay rental therefor for a period of not less than four (4) years. Should the Customer discontinue service before four (4) years shall have elapsed, the guaranteed rental then unpaid shall immediately become due and payable.

METERING

The Company may install one or more meters at its option. Metering shall be at delivery voltage, provided, however, that metering may be at a lower voltage at the option of the Company, in which case the maximum demand and kilowatt-hour energy use shall include the losses imposed by transformers between the delivery and metering points. In the latter case, the Company may at its option correct for the transformer losses by compensated metering or estimate such losses by another suitable method.

BACKUP DELIVERY SERVICE RATE B

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for backup and maintenance Delivery Service provided by the Company in conjunction with electricity produced by generation facilities located on the Customer's side of the meter which supplies all or a portion of the Customer's electric load requirements on a regular basis. Service under this rate is mandatory for Customers who take Conjunctional Service as specified in the Terms and Conditions for Delivery Service, and who, except for their own generation, would otherwise qualify for service under either Rate GV or Rate LG. This rate is not mandatory for service to Customers whose generating equipment is installed for the purpose of providing a backup or emergency supply during service outages on the Company's system, nor is it mandatory for Customers whose generation was installed prior to and has not been rebuilt since January 1, 1985. Customers taking service under this rate shall be required to execute a Service Agreement for such service which shall be available only at the delivery point specified therein.

Any Customer taking service under this rate shall be subject to the provisions of: a) Conjunctional Delivery Service under the Terms and Conditions for Delivery Service, and b) the applicable Delivery Service rate under which the Customer would otherwise take service from the Company if the Company delivered all the Customer's electricity requirements, except as such provisions may be modified by, or conflict with, the terms of this Rate Schedule.

The delivery of any electricity generated by the Customer in excess of the Customer's total electric load requirements and made available for sale to the Company or other entity shall be governed by the terms of a separate agreement.

DEFINITIONS

Standard Rate: The standard Delivery Service rate, either Primary General Delivery Service Rate GV or Large General Delivery Service Rate LG, under which the Customer would otherwise take service if the Company delivered all the Customer's electricity requirements.

Backup Contract Demand: An amount of demand which the Customer may impose on the Company's distribution system under this Rate Schedule to back up the Customer's generating facilities. Backup Contract Demand shall be the normal output rating in kilowatts of the Customer's generating facilities as determined by the Company from time to time by test operation for those Customers who have a non-zero Supplemental Demand (i.e., whose maximum demand exceeds their generating capacity). For Customers whose generating capacity is larger than their total internal load, Backup Contract Demand shall be based on thirty minute meter readings for on-peak periods during the current month and previous eleven months. For Customers who would otherwise be served under Rate GV, Backup Contract Demand shall be the greater of: a) the highest kilowatt demand during those periods, or b) 80% of the highest kilovolt-ampere demand during those periods. For Customers who would otherwise be served under Rate LG, Backup Contract Demand shall be the highest kilovolt-ampere demand during those periods.

Backup Demand: The amount of demand in kilowatts delivered to the Customer under this Rate Schedule during a particular thirty minute interval. Backup Demand shall be the lesser of: a) Backup Contract Demand minus the amount of generation registered by the generation meter, or b) the total amount of demand registered. If such amount is less than zero, it shall be deemed to be equal to zero.

Backup Energy: The amount of kilowatt-hours delivered to the Customer under this Rate Schedule during a particular thirty minute interval. Backup Energy shall be equal to Backup Demand for that thirty minute interval divided by two.

On-Peak Hours: The period from 7:00 a.m. to 8:00 p.m. weekdays excluding holidays.

Supplemental Demand: The amount of demand in kilowatts delivered to the Customer by the Company in excess of its Backup Demand during a particular thirty minute interval. Supplemental Demand shall be equal to the total amount of demand registered less the amount of Backup Demand taken. If such amount is less than zero, it shall be deemed to be equal to zero. The delivery of Supplemental Demand and related energy shall be billed under the Company's standard rate (Rate G, Rate GV, or Rate LG) available to the Customer for the amount of Supplemental Demand taken.

RATE PER MONTH

Administrative Charge.................................. $372.10 per month

Translation Charge............................…........ $62.42 per recorder per month

Issued: October 9, 2020 Issued by: /s/ Joseph A. Purington
Joseph A. Purington

Effective: January 1, 2021 Title: President and Chief Operating Officer

Demand Charges:

For Customers who take service at 115,000 volts or higher, the following charges apply:

Transmission Charge………………………………..	$1.59 per KW or KVA, whichever is whichever is applicable, of Backup Contract Demand
Stranded Cost Recovery (For Customers whose Standard Rate is Rate GV)…	$0.32 per KW or KVA, whichever is applicable, of Backup Contract Demand
Stranded Cost Recovery (For Customers whose Standard Rate is Rate LG)….	$0.24 per KW or KVA, whichever is applicable, of Backup Contract Demand

For all other Customers, in addition to the charges applicable to the Customers who take service at 115,000 volts or higher, the following additional charge applies:

Distribution Charge............................	$5.12 per KW or KVA, whichever is applicable, of Backup Contract Demand
Regulatory Reconciliation Adj.	$X.XX per KW or KVA, whichever is applicable, of Backup Contract Demand

Energy Charges:

The energy charges contained in the Standard Rate for Delivery Service, except that the distribution charge is not applicable to Customers who take service at 115,000 volts or higher.

METERING

Metering shall be provided by the Company in accordance with the provisions of the Customer's Standard Rate, except as modifications to such metering may be required by the provisions of this rate. The Company may install any metering equipment necessary to accomplish the purposes of this rate, including the measurement of output from the Customer's generating facilities. Customer shall provide suitable meter locations for the Company's metering facilities. All costs of metering equipment in excess of costs normally incurred by the Company to provide service under Customer's Standard Rate shall be borne by the Customer.

REFUSAL TO PROVIDE ACCESS

In the event that the Customer refuses access to its premises to allow the Company to install metering equipment to measure the output of the Customer's generating facilities, the Company may estimate the amount of demand and energy delivered under this rate. The Customer shall be responsible for payment of all bill amounts calculated hereunder based on such estimates of demand and energy delivered.

CONTRACT TERM

The contract term shall be for not less than one year and for such longer periods as may be determined by the operation of the sections of Customer's Standard Rate entitled "Guarantees" and "Apparatus".

SPECIAL PROVISIONS

1. Notwithstanding the general provisions of this rate schedule, the Company may include such other provisions in Customer's Service Agreement, executed pursuant to this Rate B, as may be necessary to reflect the specific circumstances of such Customer, the operating characteristics of Customer's generating equipment or any other particular facts, without limitation, which are necessary, in the Company's sole judgment and subject to Commission approval, to give effect to the purpose and intent of this rate.

2. The Customer's failure to execute a Service Agreement pursuant to the terms of this Rate B shall not preclude the application of this rate to any partial requirements service provided by the Company to the Customer.

OUTDOOR LIGHTING DELIVERY SERVICE RATE OL

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for the following applications:

(a) unmetered street and highway lighting provided to municipalities, state highway departments, and other governmental bodies;

(b) unmetered outdoor area lighting for private yards, parking lots, private roads, and other off-street applications.

All-night outdoor lighting service on an annual basis totaling approximately 3,937 hours of operation per year and midnight outdoor lighting service on an annual basis totaling approximately 1,815 hours of operation per year shall be provided for under this rate.

RATE PER MONTH

Energy Charge:

	Per Kilowatt-Hour
Transmission Charge	2.058¢
Stranded Cost Recovery	0.954¢
Regulatory Reconciliation Adjustment	X.XX¢

In addition to the energy charges above, Customers shall be assessed a monthly Distribution Rate per luminaire. The Distribution Rate includes, among other costs, the cost of the fixture and bracket. The energy charge shall be applied to the monthly kilowatt-hours specified below for the applicable fixture and service option. For outdoor lighting charges which are billed in conjunction with service rendered under a metered Rate Schedule, the kilowatt-hours used for billing purposes shall be the amount specified for the calendar month in which the meter read date occurred for service rendered under the metered Rate Schedule.

All-Night Service Option:
The monthly kilowatt-hours and distribution rates for each luminaire served under the all-night service option are shown below.

For New and Existing Installations:

Lamp Nominal Light Output Lumens	Power Rating Watts	Monthly KWH per Luminaire: Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Monthly Distribution Rate
High Pressure Sodium:														
4,000	50	27	23	22	19	16	16	16	18	21	23	24	27	$14.77
5,800	70	40	34	32	29	24	23	24	27	31	35	37	40	14.77
9,500	100	59	50	47	42	35	34	35	39	46	51	53	59	19.64
16,000	150	88	74	70	62	53	51	53	59	68	76	79	88	27.78
30,000	250	142	120	113	101	85	82	85	95	110	123	128	142	28.47
50,000	400	217	183	173	154	130	126	130	144	168	188	196	217	28.79
130,000	1,000	510	430	408	362	306	296	306	340	395	442	460	510	46.20

Issued: October 9, 2020 — Issued by: /s/ Joseph A. Purington
Joseph A. Purington

Effective: January 1, 2021 — Title: President, NH Electric Operations

Metal Halide:														
5,000	70	41	35	33	29	25	24	25	28	32	36	37	41	$15.41
8,000	100	56	47	45	40	34	33	34	38	44	49	51	56	21.09
13,000	150	88	74	71	63	53	51	53	59	68	77	80	88	28.94
13,500	175	96	81	77	68	57	56	57	64	74	83	87	96	29.55
20,000	250	134	113	107	95	80	78	80	89	104	116	121	134	29.55
36,000	400	209	176	167	149	126	122	126	140	162	181	189	209	29.82
100,000	1,000	502	423	402	356	301	292	301	335	389	435	454	502	44.71
Light Emitting Diode (LED):														
2,500	28	13	11	10	9	8	8	8	9	10	11	12	13	$10.00
4,100	36	17	14	13	12	10	10	10	11	13	15	15	17	9.97
4,800	51	24	20	19	17	14	14	14	16	18	21	21	24	10.13
8,500	92	43	36	34	30	26	25	26	29	33	37	39	43	11.17
13,300	142	66	56	53	47	40	38	40	44	51	57	60	66	12.35
24,500	220	102	86	82	73	61	59	61	68	79	89	92	102	15.54

For Existing Installations Only:

Lamp Nominal Light Output Lumens	Power Rating Watts	Monthly KWH per Luminaire Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Monthly Distribution Rate
Incandescent:														
600	105	49	41	39	35	29	28	29	33	38	42	44	49	$8.51
1,000	105	49	41	39	35	29	28	29	33	38	42	44	49	9.50
2,500	205	95	80	76	68	57	55	57	64	74	83	86	95	12.19
6,000	448	208	176	167	148	125	121	125	139	161	181	188	208	20.94
Mercury:														
3,500	100	54	46	44	39	33	32	33	36	42	47	49	54	$13.03
7,000	175	95	80	76	68	57	55	57	64	74	83	86	95	15.68
11,000	250	136	114	109	96	81	79	81	91	105	118	123	136	19.38
15,000	400	211	178	169	149	126	122	126	140	163	183	190	211	22.17
20,000	400	211	178	169	149	126	122	126	140	163	183	190	211	23.94
56,000	1,000	503	424	403	357	302	292	302	335	390	436	454	503	38.05
Fluorescent:														
20,000	330	153	129	123	109	92	89	92	102	119	133	139	153	$32.47
High Pressure Sodium in Existing Mercury Luminaires:														
12,000	150	84	71	67	59	50	49	50	56	65	73	76	84	20.32
34,200	360	192	162	154	136	115	112	115	128	149	166	173	192	26.01

The 15,000 Lumen Mercury fixture is fitted with a 20,000 lumen lamp. The 600 Lumen Incandescent fixture is fitted with a 1,000 lumen lamp.

Midnight Service Option:
The monthly kilowatt-hours and distribution rates for each luminaire served under the midnight service option are shown below.

Lamp Nominal Light Output Lumens	Power Rating Watts	Monthly KWH per Luminaire Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Monthly Distribution Rate
High Pressure Sodium:														
4,000	50	14	11	9	10	7	6	6	7	9	11	13	14	$14.77
5,800	70	20	16	13	15	11	9	9	11	13	16	20	21	14.77
9,500	100	30	23	20	21	16	13	14	16	19	24	28	31	19.64
16,000	150	44	34	29	31	24	20	21	24	28	35	42	47	27.78
30,000	250	71	56	47	51	38	32	33	38	46	57	69	76	28.47
50,000	400	109	85	72	77	58	49	51	58	70	87	105	116	28.79
130,000	1,000	255	200	170	181	136	115	119	136	165	204	246	272	46.20
Metal Halide:														
5,000	70	20	16	14	15	11	9	10	11	13	17	20	22	$15.41
8,000	100	28	22	19	20	15	13	13	15	18	23	27	30	21.09
13,000	150	44	34	30	31	24	20	21	24	28	36	43	47	28.94
13,500	175	48	38	32	34	25	22	22	26	31	38	47	51	29.55
20,000	250	67	52	45	48	36	30	31	36	43	54	65	71	29.55
36,000	400	104	82	70	74	56	47	49	56	68	84	101	111	29.82
100,000	1,000	251	196	167	178	134	114	117	134	162	201	243	268	44.71
Light Emitting Diode (LED):														
2,500	28	13	11	10	9	8	8	8	9	10	11	12	13	$10.00
4,100	36	17	14	13	12	10	10	10	11	13	15	15	17	9.97
4,800	51	24	20	19	17	14	14	14	16	18	21	21	24	10.13
8,500	92	43	36	34	30	26	25	26	29	33	37	39	43	11.17
13,300	142	66	56	53	47	40	38	40	44	51	57	60	66	12.35
24,500	220	102	86	82	73	61	59	61	68	79	89	92	102	15.54

MODIFICATION OF SERVICE OPTION

Municipal and state roadway lighting Customers may request a modification of service from the all-night service option to the midnight service option during the calendar months of January and February of each year, otherwise known as the open enrollment period. Requests received from municipal and state roadway lighting Customers after the open enrollment period shall be implemented during the subsequent open enrollment period, unless the Company determines that it is feasible and practicable to implement the request prior to the subsequent enrollment period. All other Customers may request a modification of service from the all-night service option to the midnight service option at any time. Customers requesting a modification of service from the all-night service option to the midnight service option are responsible to pay to the Company the installed cost of any additional equipment required to provide service under the midnight service option. The installed cost includes the cost of the additional equipment, labor, vehicles and overheads. The Customer is responsible to pay such costs prior to the installation of the equipment. If such a request is made concurrent with the Company's existing schedule for lamp replacement and maintenance, the Customer is responsible to pay to the Company the cost of any additional equipment required, including overheads. The Customer is responsible to pay such costs prior to the installation of the equipment.

Customers requesting a modification of service from the midnight service option to the all-night service option are responsible to pay to the Company the installation cost of the equipment required to provide service under the all-night service option. The installation cost includes the cost of labor, vehicles and overheads. The Customer is responsible to pay such costs prior to the installation of the equipment. If such a request is made concurrent with the Company's existing schedule for lamp replacement and maintenance, no additional costs are required to modify service from the midnight service option to the all-night service option.

The Company will utilize fixed price estimates per luminaire for the installed cost, the additional equipment cost and the equipment installation cost and will update the fixed price estimates per luminaire each year based upon current costs. In the event traffic control is required during a modification of service option or for equipment repair, the Customer is responsible to coordinate and to provide traffic control and to pay all costs associated with traffic control. In the event the Customer is a residential or General Delivery Service Rate G Customer, the Company may coordinate and provide traffic control on the Customer's behalf and the Customer shall reimburse the Company for all costs associated with the traffic control provided by the Company. The scheduling of work associated with the modification of a service option will be made at the Company's discretion with consideration given to minimizing travel and set-up time.

LEAP YEAR ADJUSTMENT TO ENERGY

During any leap year, the energy (kilowatt-hour) usage during the month of February for all fixtures shall be increased by 3.4 percent for the purpose of determining total energy charges under this rate.

CONTRACT TERM

The contract term for outdoor area lighting shall be for not less than one year.

MAINTENANCE

The Company shall exercise reasonable diligence to ensure all street and highway lamps are burning and shall make replacements promptly when notified of outages. Lamp replacement, maintenance and cleaning of street and highway lighting fixtures will normally be performed on a periodic basis in accordance with generally accepted utility practices and consistent with any manufacturer's recommendations. Lamp replacement and maintenance of outdoor area lighting will be performed as soon as possible following notification by the Customer of the need for such service, but the Company shall not be required to perform any such replacement or maintenance except during regular working hours.

NEW INSTALLATIONS, EXTENSIONS AND REPLACEMENTS

New installations, extensions and replacements using overhead wiring, a standard fixture, an all-night service option photocell and located upon existing poles of the Company, shall be made at the expense of the Company.

Except for the excess costs of underground facilities to be apportioned as set forth in the provisions for underground electric distribution facilities specified in the Company's "Information and Requirements for Electric Supply", any costs incurred in connection with new installations, extensions and replacements which exceed the costs of a standard outdoor lighting fixture equipped with an all-night service option photocell located on existing poles with overhead wiring shall be borne by the Customer. Such excess costs shall be paid as a lump sum prior to the installation of the equipment.

In the case of new installations, extensions and replacements which make use of underground conductors for supply and distribution and/or of standards or poles employed exclusively for lighting purposes, the Company reserves the right to require the Customer to furnish, own, and maintain such underground supply and distribution facilities and/or the standards or poles.

If the Company's right under the preceding paragraph is exercised and the Company thereby is relieved of the cost of installing the customary overhead wires and appurtenances and the customary dual purpose poles, the Company shall:

1. pay to the Customer the sum of the following:

    a. the estimated saving in investment to the Company represented by the estimated cost of the customary overhead wires and appurtenances;

    b. such portion, if any, of the estimated cost to the Company of the customary dual purpose poles as would normally be allocated to lighting purposes;

2. have the right, without payment of any charge, to attach its wires, fixtures, brackets, luminaires, transformers, and other equipment to the standards or poles owned by the Customer.

Should the standards or poles furnished, owned, and maintained by the Customer be located in a public highway, the Customer shall procure and furnish to the Company a license under the Public Laws of New Hampshire (R.S.A. Chapter 231) covering such interest as the Company may have in the standards or poles, including their wires, fixtures, brackets, luminaires, transformers, and other equipment.

For outdoor area lighting installations, the Customer shall provide without expense or cost to the Company, all permits, consents, or easements necessary for the erection, maintenance, and operation of the Company's facilities, including the right to cut and trim trees and bushes wherever necessary; and the Company shall not be required to move its facilities to another location on the Customer's premises unless the Customer shall bear the cost thereof. The Company reserves the right to restrict such installations under this rate to those which will yield a reasonable return to the Company and to areas which are easily accessible by service truck. Installations of 4,000 lumen (50 watt) high pressure sodium luminaires will not be allowed as replacements of existing 3,500 lumen (100 watt) mercury luminaires unless the Customer agrees to pay for the remaining unexpired life of the retired equipment, including the unexpired portion of the cost of installation and the cost of removal less any salvage value of the equipment removed.

The total number of new installations, extensions, and replacements for outdoor lighting equipment may be limited by the Company in any calendar year to three (3) percent of the total number of units billed to the particular Customers at the beginning of such calendar year.

In cases where the Customer requests a change in or removal of existing outdoor lighting equipment which has not reached the end of its normal useful life, the Company may require the Customer to pay for the remaining unexpired life of the retired equipment, including the unexpired portion of the cost of installation and the cost of removal less any salvage value of the equipment removed.

All poles, wires, fixtures, brackets, luminaires, transformers, and other equipment furnished by the Company shall be maintained by it and title to such shall in all cases remain vested in the Company.

ENERGY EFFICIENT OUTDOOR LIGHTING DELIVERY SERVICE RATE EOL

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this unmetered rate is available to any federal, state, county, municipal or other governmental unit, or department or agency of the government. Service under this rate is for delivery and maintenance of street and area lighting service to fixtures utilizing high pressure sodium, metal halide, light emitting diode ("LED") or other energy efficient technology accepted by the Company, for which the Customer has paid the installed cost of fixtures and brackets. It is available at the Customer's option to those Customers who sign a Service Agreement to receive all of their street and area lighting service requirements under Rate EOL where feasible.

Customers choosing to convert from service under Outdoor Lighting Delivery Service Rate OL to service under Rate EOL must:

(a) contribute to the Company the remaining unexpired life of currently installed high pressure sodium and metal halide fixtures and brackets which the Customer wishes to remain in service on the date that service under this rate is initiated;

(b) contribute to the Company the cost of removal and remaining unexpired life of any street and area lighting fixtures and brackets as of the date that such fixtures are removed and replaced with energy efficient lighting technology in accordance with this Rate Schedule;

(c) pay the Company the installed cost for all new high pressure sodium and metal halide fixtures and brackets placed into service under this rate, and;

(d) furnish any fixtures utilizing other lighting technologies accepted by the Company, and pay either the Company or a private line contractor, as described under the "Additional Requirements" section below, for the installation of these fixtures.

The Company will perform all maintenance of lighting fixtures under this rate. The Company will hold title to all fixtures during the time they are installed.

All-night outdoor lighting service on an annual basis totaling approximately 4,345 hours of operation per year and midnight outdoor lighting service on an annual basis totaling approximately 2,005 hours of operation per year shall be provided for under this rate.

LIMITATIONS ON AVAILABILITY

The availability of this rate to any Customer is contingent upon the availability to the Company of personnel and/or other resources necessary to perform the conversion of existing fixtures in accordance with the time schedule specified in the Service Agreement.

ADDITIONAL REQUIREMENTS FOR TECHNOLOGIES OTHER THAN HIGH PRESSURE SODIUM OR METAL HALIDE

Fixtures utilizing technologies other than High Pressure Sodium or Metal Halide must be provided by the Customer for installation on the Company's facilities. Fixtures shall be accepted by the Company in advance of installation and must be compatible with existing line voltage, brackets and photoelectric controls, and must require no special tools or training to install and maintain.

Customers who are replacing existing fixtures with these technologies are responsible for the cost of removal and installation. Customers may choose to have this work completed by the Company or may opt to hire and pay a private line contractor to perform the work. Any private contractor shall have all the requisite training, certifications and insurance to safely perform the required installations, and shall be licensed by the State and accepted by the Company. Prior to commencement of work, the municipality must provide written certification of the qualifications to the Company. Contractors shall coordinate the installation work with the Company and submit a work plan subject to approval by the Company. The Customer shall bear all expenses related to the use of such labor, including any expenses arising from damage to the Company’s electrical system caused by the contractor’s actions.

SERVICE AGREEMENT

The Customer shall sign a Service Agreement governing the contribution for the remaining unexpired life of the existing street lighting fixtures and brackets, the contribution for the installed cost of the new fixtures and brackets, and the conversion of existing fixtures.

SERVICE DURING THE CONVERSION PERIOD FROM RATE OL TO RATE EOL

Service under this rate shall be implemented on a prorated basis, according to the number of fixtures which have been converted. Therefore, during the conversion period a portion of the Customer's street and area lighting requirements may be served under Outdoor Lighting Delivery Service Rate OL for those fixtures which have not yet been converted under this Rate.

MONTHLY RATES

Energy Charge:

	Per Kilowatt-Hour
Transmission Charge	2.058¢
Stranded Cost Recovery..................................	0.954¢
Regulatory Reconciliation Adjustment……….	X.XX¢

In addition to the energy charges above, Customers shall be assessed the monthly Distribution Rates shown below. The energy charge shall be applied to the monthly kilowatt-hours specified below for the applicable fixture and service option. For outdoor lighting charges which are billed in conjunction with service rendered under a metered Rate Schedule, the kilowatt-hours used for billing purposes shall be the amount specified for the calendar month in which the later meter read date occurred for service rendered under the metered Rate Schedule.

All-Night Service Option:
The monthly kilowatt-hours and distribution rates for each fixture served under the all-night service option are shown below.

Lamp Nominal Light Output Lumens	Power Rating Watts	Monthly KWH per Fixture Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Monthly Distribution Rate
High Pressure Sodium:														
4,000	50	27	23	22	19	16	16	16	18	21	23	24	27	$6.12
5,800	70	40	34	32	29	24	23	24	27	31	35	37	40	6.43
9,500	100	59	50	47	42	35	34	35	39	46	51	53	59	6.85
16,000	150	88	74	70	62	53	51	53	59	68	76	79	88	7.51
30,000	250	142	120	113	101	85	82	85	95	110	123	128	142	8.73
50,000	400	217	183	173	154	130	126	130	144	168	188	196	217	10.44
130,000	1,000	510	430	408	362	306	296	306	340	395	442	460	510	17.11
Metal Halide:														
5,000	70	41	35	33	29	25	24	25	28	32	36	37	41	$6.45
8,000	100	56	47	45	40	34	33	34	38	44	49	51	56	6.79
13,000	150	88	74	71	63	53	51	53	59	68	77	80	88	7.52
13,500	175	96	81	77	68	57	56	57	64	74	83	87	96	7.69
20,000	250	134	113	107	95	80	78	80	89	104	116	121	134	8.55
36,000	400	209	176	167	149	126	122	126	140	162	181	189	209	10.27
100,000	1,000	502	423	402	356	301	292	301	335	389	435	454	502	16.93

LED’s and other technologies accepted by the Company:

	Per Fixture	Per Watt
Monthly Distribution Rates	$3.01	$0.01058

Monthly KWH per Fixture will be calculated to the nearest whole (1.0) KWH as follows:
Total Fixture Wattage divided by 1,000 times the monthly hours of operation below

Monthly Hours of Operation

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
421	350	342	342	257	230	248	283	316	372	399	433

Issued: October 9, 2020 Issued by: /s/ Joseph A. Purington
Joseph A. Purington

Effective: January 1, 2021 Title: President and Chief Operating Officer

Midnight Service Option:
The monthly kilowatt-hours and distribution rates for each fixture served under the midnight service option are shown below.

Lamp Nominal Light Output Lumens	Power Rating Watts	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Monthly Distribution Rate
		Monthly KWH per Fixture												
High Pressure Sodium:														
4,000	50	14	11	9	10	7	6	6	7	9	11	13	14	$6.12
5,800	70	20	16	13	15	11	9	9	11	13	16	20	21	6.43
9,500	100	30	23	20	21	16	13	14	16	19	24	28	31	6.85
16,000	150	44	34	29	31	24	20	21	24	28	35	42	47	7.51
30,000	250	71	56	47	51	38	32	33	38	46	57	69	76	8.73
50,000	400	109	85	72	77	58	49	51	58	70	87	105	116	10.44
130,000	1,000	255	200	170	181	136	115	119	136	165	204	246	272	17.11
Metal Halide:														
5,000	70	20	16	14	15	11	9	10	11	13	17	20	22	$6.45
8,000	100	28	22	19	20	15	13	13	15	18	23	27	30	6.79
13,000	150	44	34	30	31	24	20	21	24	28	36	43	47	7.52
13,500	175	48	38	32	34	25	22	22	26	31	38	47	51	7.69
20,000	250	67	52	45	48	36	30	31	36	43	54	65	71	8.55
36,000	400	104	82	70	74	56	47	49	56	68	84	101	111	10.27
100,000	1,000	251	196	167	178	134	114	117	134	162	201	243	268	16.93

LED's and other technologies accepted by the Company:

	Per Fixture	Per Watt
Monthly Distribution Rates	$3.01	$0.01058

Monthly KWH per Fixture will be calculated to the nearest whole (1.0) KWH as follows:
Total Fixture Wattage divided by 1,000 times the monthly hours of operation below

Monthly Hours of Operation

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
213	175	150	120	106	91	97	116	138	170	214	226

LEAP YEAR ADJUSTMENT TO ENERGY

During any leap year, the energy (Kilowatt-hour) usage during the month of February for all fixtures shall be increased by 3.4 percent for the purpose of determining total energy charges under this rate.

Issued: October 9, 2020

Issued by: /s/ Joseph A. Purington
Joseph A. Purington

Effective: January 1, 2021

Title: President and Chief Operating Officer

MAINTENANCE

The Company shall exercise reasonable diligence to ensure that all lamps are burning and shall make replacements promptly when notified of outages. However, the Company shall not be required to perform any replacements or maintenance except during regular working hours.

For high pressure sodium and metal halide fixtures, lamp replacement, maintenance and cleaning of lighting fixtures will normally be performed on a periodic basis in accordance with generally accepted utility practices and consistent with any manufacturer's recommendations.

For fixtures utilizing technologies other than high pressure sodium or metal halide, the Company will be responsible for correcting Company system voltage problems at no charge to the Customer. When the Company responds to a report of a non-working fixture not related to voltage, the Customer will be assessed a per-fixture per-visit charge to replace photoelectric controls or to remove an otherwise non-working fixture and return it to the Customer.

	Per-Fixture Per-Visit
Maintenance Charge……………………………………	$189.00 plus cost of materials

USE OF ADVANCED CONTROLS

Where lighting controls that meet the current ANSI C12.20 standard have been installed that allow for variation from the Company's outdoor lighting hours schedule under All-Night Schedule or Midnight Schedule, the Customer must provide verification of such installation to the Company and a schedule indicating the expected average operating wattage of lights subject to the Customer's control and operation. Upon installation and at any time thereafter, the Customer must also provide the Company access, either directly or indirectly, to the data from the Customer's control system in order for the Company to verify the measured energy use of the lighting systems and modify the billed usage as appropriate on a prospective basis. The Customer shall provide a report annually which provides actual monthly operating usage of such lighting systems.

The schedule of average operating wattage ratings may be revised once per year at the request of the Customer. However, it is the Customer's responsibility to immediately notify the Company of any planned or unplanned changes to its scheduled usage to allow for billing adjustments as may be needed.

The charge for the monthly kilowatt-hours shall be determined on the basis of the average operating wattage of the light sources resulting from installed control adjustments established at the beginning of the billing period multiplied by the average monthly hours of the outdoor lighting hours schedule. The wattage ratings shall allow for the billing of kilowatt-hours according to the schedule submitted by the Customer to the Company and reflect any adjustments from the lighting control system including, but not limited to, fixture trimming, dimming, brightening, variable dimming, and multiple hourly schedules.

MODIFICATION OF SERVICE OPTION

Municipal and state roadway lighting Customers may request a modification of service from the all-night service option to the midnight service option during the calendar months of January and February of each year, otherwise known as the open enrollment period. Requests received from municipal and state roadway lighting Customers after the open enrollment period shall be implemented during the subsequent open enrollment period, unless the Company determines that it is feasible and practicable to implement the request prior to the subsequent enrollment period. All other Customers may request a modification of service from the all-night service option to the midnight service option at any time. Customers requesting a modification of service from the all-night service option to the midnight service option are responsible to pay to the Company the installed cost of any additional equipment required to provide service under the midnight service option. The installed cost includes the cost of the additional equipment, labor, vehicles and overheads. The Customer is responsible to pay such costs prior to the installation of the equipment. If such a request is made concurrent with the Company's existing schedule for lamp replacement and maintenance, the Customer is responsible to pay to the Company the cost of any additional equipment required, including overheads. The Customer is responsible to pay such costs prior to the installation of the equipment.

Customers requesting a modification of service from the midnight service option to the all-night service option are responsible to pay to the Company the installation cost of the equipment required to provide service under the all-night service option. The installation cost includes the cost of labor, vehicles and overheads. The Customer is responsible to pay such costs prior to the installation of the equipment. If such a request is made concurrent with the Company's existing schedule for lamp replacement and maintenance, no additional costs are required to modify service from the midnight service option to the all-night service option.

The Company will utilize fixed price estimates per fixture for the installed cost, the additional equipment cost and the equipment installation cost and will update the fixed price estimates per fixture each year based upon current costs. In the event traffic control is required during a modification of service option or for equipment repair, the Customer is responsible to coordinate and to provide traffic control and to pay all costs associated with traffic control. The scheduling of work associated with the modification of a service option will be made at the Company's discretion with consideration given to minimizing travel and set-up time.

NEW INSTALLATIONS, EXTENSIONS AND REPLACEMENTS

No additional cost, other than a contribution for the installed cost of new fixtures and brackets as provided for herein, shall be assessed for fixtures and brackets which are attached to existing poles utilizing overhead secondary wiring. Any cost incurred in connection with the installation of lighting facilities which exceeds the cost of using existing poles with overhead secondary wiring shall be borne by the Customer.

Except for the excess costs of underground facilities to be apportioned as set forth in the provisions for underground electric distribution facilities specified in the Company's "Information and Requirements for Electric Service", any cost incurred in connection with the installation of poles, transformers, wiring, or any other facilities or equipment used exclusively for lighting purposes shall be borne by the Customer.

In such cases, the Company shall credit the Customer with the portion, if any, of the estimated cost of such facilities which would normally be allocated to lighting purposes.

Any cost incurred in connection with new installations, or with the replacement or removal of existing fixtures and/or brackets shall be borne by the Customer. Such costs shall include the installed cost of the new fixtures and/or brackets in the case of new installations and replacements, and the cost of removal of the existing fixtures and/or brackets, less any salvage value of such fixtures and/or brackets which are removed from service.

In the case of new installations, extensions and replacements which make use of underground conductors for supply and distribution and/or of standards or poles employed exclusively for lighting purposes, the Company reserves the right to require the Customer to furnish, own, and maintain such underground supply and distribution facilities and/or the standards or poles.

If the Company's right under the preceding paragraph is exercised and the Company thereby is relieved of the cost of installing the customary overhead wires and appurtenances and the customary dual purpose poles, the Company shall:

1. pay to the Customer the sum of the following:

    a. the estimated saving in investment to the Company represented by the estimated cost of the customary overhead wires and appurtenances;

    b. such portion, if any, of the estimated cost to the Company of the customary dual purpose poles as would normally be allocated to lighting purposes;

2. have the right, without payment of any charge, to attach its wires, brackets, fixtures, transformers, and other equipment to the standards or poles owned by the Customer.

Should the standards or poles furnished, owned, and maintained by the Customer be located in a public highway, the Customer shall procure and furnish to the Company a license under the Public Laws of New Hampshire (R.S.A. Chapter 231) covering such interest as the Company may have in the standards or poles, including their wires, brackets, fixtures, transformers, and other equipment.

For outdoor area lighting installations, the Customer shall provide without expense or cost to the Company, all permits, consents, or easements necessary for the erection, maintenance, and operation of the Company's facilities, including the right to cut and trim trees and bushes wherever necessary; and the Company shall not be required to move its facilities to another location on the Customer's premises unless the Customer shall bear the cost thereof. The Company reserves the right to restrict such installations under this Rate to areas which are easily accessible by service truck.

All poles, wires, brackets, fixtures, transformers, and other equipment furnished by the Company shall be maintained by it and title to such shall in all cases remain vested in the Company.

DEFAULT ENERGY SERVICE RATE DE

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for Default Energy Service in conjunction with the applicable Delivery Service Rate Schedule. It is available to Customers who are not receiving Supplier Service or Self-Supply Service.

Notwithstanding any other Tariff provision or Special Contract terms, no discount shall be applied to this rate.

RATE PER MONTH

Applicable to customers receiving Delivery Service under Primary General Delivery Service Rate GV, Large General Delivery Service Rate LG and Backup Delivery Service Rate B, including any outdoor area lighting taken in conjunction with these accounts under Outdoor Lighting Delivery Service Rate OL:

Per Kilowatt-Hour

	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020
Base Rate	10.228¢	7.674¢	7.127¢	6.143¢	5.384¢	5.830¢
Reconciliation Adjustment	0.195¢	0.195¢	0.195¢	0.195¢	0.195¢	0.195¢
Renewable Portfolio Standard	0.779¢	0.779¢	0.779¢	0.779¢	0.779¢	0.779¢
Administrative & General	0.095¢	0.095¢	0.095¢	0.095¢	0.095¢	0.095¢
Total Rate Per Month	11.297¢	8.743¢	8.196¢	7.212¢	6.453¢	6.899¢

Applicable to all other customers:

	February 2020 – July 2020 Per Kilowatt-Hour
Base Rate	7.404¢
Reconciliation Adjustment	0.028¢
Renewable Portfolio Standard	0.779¢
Administrative & General	0.095¢
Total Rate Per Month	8.306¢

Issued: October 9, 2020

Issued by: /s/ Joseph A. Purington
Joseph A. Purington

Effective: January 1, 2021

Title: President and Chief Operating Officer

SMART START
ENERGY EFFICIENCY PROGRAM

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for the installation of energy efficiency and load management measures for municipalities in offices, schools, and other municipal buildings. The energy efficiency and load management measures will be installed at the Company's expense and the Customer shall reimburse the Company through charges added to the Customer's regular monthly bill. Upon the Customer's request, the Company may utilize a fixed price estimate for the installed cost of energy efficiency and load management measures installed by the Company to determine eligibility and the monthly charges under this rate. If the Customer enters into an agreement based upon the fixed price estimate, both the Customer and the Company will be bound by that fixed price estimate. This rate is for a basic utility service and the Customer is liable for payment of the charges under this rate under the same conditions as any other charges for basic utility service including, but not limited to, the Customer's service being subject to disconnection for nonpayment in accordance with the rules of the Commission.

At its sole discretion, the Company shall determine eligibility for service under this rate subject to (1) the availability of funds budgeted for this program, (2) the suitability of approved energy efficiency and load management measures for the Customer's location and the likelihood that the measures will be used and useful throughout their estimated life, (3) a minimum project cost requirement of $1,000 which may be met by aggregating project costs from multiple delivery service accounts, and (4) the Company's determination that the measures chosen are estimated to produce sufficient energy or demand savings to offset the total costs of the measures. Although the Company expects that all Customers participating in the Smart Start Energy Efficiency Program will receive lower monthly electric bills, there is no guarantee of savings.

Any Customer taking service under this rate must be and remain a full requirements delivery service Customer. In the event the Customer does not remain a full requirements delivery service Customer, any remaining charges under this rate shall immediately become due and payable.

COMPANY RESPONSIBILITIES

The Company will act as the Customer's agent in selecting energy efficiency and or load management measures which are suitable for the Customer's end uses of electricity and which are estimated to produce sufficient savings in energy usage or demand. The Company may arrange for a supplier or contractor (1) to install the measures (2) to instruct the Customer on the proper use, operation and maintenance of the measures and (3) to certify that the measures are properly installed and operating as designed. Upon notification by the Customer that work is complete, the Company will verify that the measure(s) have been installed and arrange for payment to the contractor.

After receiving notice from the Customer, the Company will evaluate any report of a failed measure(s), and at its option, the Company will cause the measure(s) to be repaired or replaced when necessary or will terminate charges under this rate.

The Company will inform all new Customers at a location where energy efficiency or load management measures have been installed as to the existence of any unbilled charges remaining under this rate for that location. If the former Customer received service under an accelerated payment period term, the Company will inform the new Customer that they may revert at any time to the minimum monthly charge that was available to the former Customer. The Company will also inform these Customers of the benefits associated with the measure(s) and their responsibility for the payment of the remaining charges under this rate and other obligations.

CUSTOMER RESPONSIBILITIES

Prior to the installation of any energy efficiency or load management measures, the Customer will sign a Smart Start Agreement which will provide that the Customer is responsible for:

(1) payment of the monthly charges under this rate in addition to all other charges on the monthly bill;
(2) informing the Company if the measures fail completely or malfunction so that the estimated reductions in demand and energy use cannot be realized;
(3) maintaining the energy efficiency or load management measures at the service location and taking reasonable steps to prevent damage to such measures;
(4) becoming fully informed concerning the routine operation and maintenance of the energy efficiency or load management measures installed at the service location;
(5) allowing access by the Company, at reasonable times, for any inspection or repair of the energy efficiency or load management measures to the extent the Company is responsible for such repairs as described above; and
(6) accepting responsibility for the cost of out of warrantee repairs. Customers may accept such responsibility through any of the following:
    (a) the customer may repair the measure(s) themselves,
    (b) the customer and/or customer's casualty insurance may pay for repairs,
    (c) the customer may agree to an extension of the number of monthly payments to cover the Company's cost of repair.

A Customer's obligation to pay for the measure(s) ends when the Customer closes their account. If the Customer is the owner or lessor of the premises, the Customer must inform all prospective purchasers or renters of the location that there is an unexpired obligation under this rate. Whenever a Customer applies for service at a location which was the subject of a previous Smart Start Agreement, payment for which has not been completed, such Customer shall become responsible for the remaining balance. If the location was the subject of an accelerated payment term, the new Customer has the option to revert at any time to the minimum monthly charge that was available to the former Customer. Acceptance of electric service constitutes acceptance of the obligations under this rate by the new Customer.

LANDLORD'S AND LESSOR'S RESPONSIBILITIES

In order to be eligible to accept the installation of the energy efficiency or load management measures in a location which is rented or leased to tenants who currently are Customers of the Company or future tenants of such locations who will apply for service from the Company at such locations, the owner and the landlord or lessor (in case the landlord or lessor is not the owner) must enter into a Smart Start Agreement under which they agree:

(1) to cooperate in obtaining the consent of any existing tenants to enter into a Smart Start Agreement with the Company,
(2) to inform all prospective new tenants of the obligation to enter into a Smart Start Agreement for the remaining balance of any previous Smart Start Agreement attributable to the rented or leased location; and
(3) to inform all subsequent owners or lessors of these obligations with respect to informing tenants of their obligation to enter into a Smart Start Agreement.

Landlords and lessors of service locations must also agree to allow the Company access to any measures in order to inspect or repair the measures.

PRICING AND CONTRACT TERM

The Smart Start Agreement will specify the monthly charge and the term of the payment period. A Customer can choose to accelerate the payment period term by paying a higher monthly charge or a Customer can choose to pay the remaining balance owed to the Company at any time. Customers selecting an accelerated payment period term can revert at any time to the minimum monthly charge available to the Customer. The term of the Smart Start Agreement may be extended by the Company to recover its costs for out of warrantee repairs or missed payments.

ENERGY EFFICIENCY LOAN PROGRAM

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this program shall allow Customers installing energy-efficiency measures under an energy efficiency program offered by the Company and approved by the Commission ("Participating Customers") to borrow all or a portion of the Customer's share of the installed cost of the energy-efficiency measures ("Customer Loan Amount") through an additional charge on their monthly electric service bill issued by the Company.

It is available to Residential Participating Customers with existing agreements as well as Residential Participating Customers who meet the following qualifications:

1. The Customer must own the residential property where the energy-efficiency measures are installed; and
2. The Customer must have an active Delivery Service account with the Company for the property where the energy-efficiency measures are installed and receive Delivery Service under Residential Delivery Service Rate R or Residential Time-of-Day Delivery Service Rate R-OTOD; and
3. The Customer must have a Fair Isaac and Company ("FICO") credit score of 680 or higher; and
4. The Customer must have good credit with the Company, which is defined as a Customer that has not received a disconnect notice from the Company during the twelve months preceding the Customer's request for service under this program; and
5. The Customer Loan Amount must be greater than or equal to $500 and less than or equal to $2,000 and must not exceed the Customer's share of the installed cost of the energy-efficiency measures installed under the Company's approved energy-efficiency program.

It is available to Non-Residential Participating Customers with existing agreements as well as Non-Residential Participating Customers who are not eligible under the Smart Start Energy Efficiency Program Rate SSP and who meet the following qualifications:

1. The Customer must own or lease the property where the energy-efficiency measures are installed; and
2. The Customer must have an active Delivery Service account with the Company for twelve consecutive months at the property where the energy efficiency measures are installed and receive Delivery Service under General Delivery Service Rate G, General Time-of-Day Delivery Service Rate G-OTOD, or Primary General Delivery Service Rate GV; and
3. The Customer must have good credit with the Company, which is defined as a Customer that has not received a disconnect notice from the Company during the twelve months preceding the Customer's request for service under this program and has no outstanding bill amounts owed to the Company; and

4. The Customer Loan Amount must be greater than or equal to $1,500 and less than or equal to $20,000 and must not exceed the Customer's share of the installed cost of the energy-efficiency measures installed under the Company's approved energy-efficiency programs.

At its sole discretion, the Company shall determine eligibility for service under this program subject to the availability of program funds.

Any Customer taking service under this program must remain a Delivery Service Customer of the Company at the property where the energy-efficiency measures are installed. In the event the Customer does not remain a Delivery Service Customer of the Company at the property where the energy-efficiency measures are installed, any remaining charges under this program shall immediately become due and payable.

CUSTOMER LOAN AGREEMENT

Participating Customers shall be required to execute a separate Customer Loan Agreement which will specify the fixed monthly charge and the terms of the payment period. A Customer can choose to pay the remaining balance owed to the Company at any time. A late payment charge as described in the Terms and Conditions for Delivery Service section of the Company's Tariff is applicable to the monthly charges rendered under this program. Participating Customers are not subject to disconnection of electric service for nonpayment of the charges under this program.

The Customer Loan Amount shall be paid to the Company by the Participating Customer through a fixed monthly charge applied over a term of months as established in the Customer Loan Agreement. Residential Participating Customers may specify the repayment term of the Customer Loan Amount subject to a maximum repayment term limit of 24 months. When requested by the customer, the term of a Residential Customer Loan Agreement may be extended or payments temporarily deferred for financial reasons to a maximum term length of 36 months. Non-Residential Participating Customers can choose to accelerate the payment period term specified in the Customer Loan Agreement by paying a higher monthly charge and can revert at any time to the minimum monthly charge available to the Customer as specified in the Customer Loan Agreement. When requested by the customer, the term of a Non-Residential Customer Loan Agreement may be extended by the Company to recover its costs for missed payments or payments temporarily deferred for financial reasons at the discretion of the Company.

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Report of Proposed Rate Changes - Settlement Rates

Tariff NHPUC No. 9

Date Filed: October 9, 2020
Date Effective: January 1, 2021

(A)	(B)	(C)	(D)	(E)	(F) = (E) - (D)	(G) = (F) / (D)
	Effect of	Average	Estimated Annual Revenue (a)		Proposed Annual Change	
	Proposed	Number of	Current	Proposed		
Class of Service	Change	Customers	Rates (b)	Rates (c)	Revenue	Percent
Residential Service Rate R and R-OTOD	Increase	439,078	$ 587,513,346	$ 615,117,807	$27,604,461	4.7%
General Service Rate G and Rate G-OTOD	Increase	75,983	$ 284,151,913	$ 295,712,356	$11,560,443	4.1%
Primary General Service Rate GV	Increase	1,393	$ 206,952,027	$ 211,938,457	$ 4,986,430	2.4%
Large General Service Rate LG	Increase	121	$ 141,139,745	$ 143,902,776	$ 2,763,031	2.0%
Outdoor Lighting Service Rate OL and Rate EOL	Decrease	773	$ 10,675,492	$ 9,328,554	$ (1,346,938)	-12.6%
Total (a)	Increase	517,349	$ 1,230,432,523	$ 1,275,999,950	$45,567,427	3.7%

Notes:
(a) Based on actual sales to customers for the twelve-month period ending December 31, 2018, normalized for lighting inventory as of December 2018.
(b) Current rate revenue is based on distribution rates effective January 1, 2018, and transmission, stranded cost recovery, system benefits, and energy service rates in effect as of the filing date. Support for amounts are shown in Appendix 10, pages 11 through 21
(c) Proposed rate revenue is based on proposed distribution rates and includes base increase, recoupment and surcredit. No changes in other rate components have been reflected. Support for amounts are shown in Appendix 10, pages 11 through 21.

Signed By: /s/ Edward A. Davis
Edward A. Davis

Title: Director, Rates

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Report of Proposed Rate Changes
Current Rates

Tariff NHPUC No. 9

Date Filed: October 9, 2020
Date Effective: January 1, 2021

(A) Class	(B) Current Distribution	(C) Current Transmission	(D) Current SCRC	(E) Current System Benefits	(F) Current Energy Service (b)	(G) = Sum of (B) to (F) Total Revenue
Residential Service Rate R (a)	$ 202,012,310	$ 97,714,996	$ 32,002,049	$ 24,330,751	$ 231,453,240	$ 587,513,346
General Service Rate G	84,312,407	49,219,118	15,488,590	12,854,042	122,277,756	284,151,913
Primary General Service Rate GV	36,426,129	44,111,953	13,492,968	12,396,614	100,524,363	206,952,027
Large General Service Rate LG	20,150,790	29,120,817	7,079,752	9,308,181	75,480,205	141,139,745
Outdoor Lighting Rates OL, EOL	7,590,790	586,558	271,903	211,765	2,014,476	10,675,492
Total Retail	$ 350,492,426	$ 220,753,442	$ 68,335,262	$ 59,101,353	$ 531,750,040	$ 1,230,432,523

Notes:
(a) Revenues for Residential Rate R do not include credits issued to qualifying customers under the Residential Electric Assistance Program.
(b) For purposes of this calculation, all customers are assumed to receive service under the Energy Service rate.
(c) Support for amounts shown above is contained in Appendix 10, pages 11 through 21.

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Report of Proposed Rate Changes
Permanent Rates

Tariff NHPUC No. 9

Date Filed: October 9, 2020
Date Effective: January 1, 2021

(A)	(B)	(C)	(D)	(E)	(F)	(G) = Sum of (B) to (F)
	Proposed			Current	Current	
	Permanent	Current	Current	System	Energy	Total
Class	Distribution	Transmission	SCRC	Benefits	Service (b)	Revenue
Residential Service Rate R (a)	$ 229,616,771	$ 97,714,996	$ 32,002,049	$ 24,330,751	$ 231,453,240	$ 615,117,807
General Service Rate G	95,872,850	49,219,118	15,488,590	12,854,042	122,277,756	295,712,356
Primary General Service Rate GV	41,412,559	44,111,953	13,492,968	12,396,614	100,524,363	211,938,457
Large General Service Rate LG	22,913,821	29,120,817	7,079,752	9,308,181	75,480,205	143,902,776
Outdoor Lighting Rates OL, EOL	6,243,852	586,558	271,903	211,765	2,014,476	9,328,554
Total Retail	$ 396,059,853	$ 220,753,442	$ 68,335,262	$ 59,101,353	$ 531,750,040	$ 1,275,999,950

Notes:
(a) Revenues for Residential Rate R do not include credits issued to qualifying customers under the Residential Electric Assistance Program.
(b) For purposes of this calculation, all customers are assumed to receive service under the Energy Service rate.
(c) Support for amounts shown above is contained in Appendix 10, pages 11 through 21.

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Report of Proposed Rate Changes
Incremental Increase/(Decrease)

Tariff NHPUC No. 9

Date Filed: October 9, 2020
Date Effective: January 1, 2021

(A) Class	(B) Proposed Permanent Distribution (b)	(C) Current Transmission	(D) Current SCRC	(E) Current System Benefits	(F) Current Energy Service (c)	(G) = Sum of (B) to (F) Total Revenue
Residential Service Rate R (a)	$ 27,604,461	$ -	$ -	$ -	$ -	$ 27,604,461
General Service Rate G	11,560,443	-	-	-	-	11,560,443
Primary General Service Rate GV	4,986,430	-	-	-	-	4,986,430
Large General Service Rate LG	2,763,031	-	-	-	-	2,763,031
Outdoor Lighting Rates OL, EOL	(1,346,938)	-	-	-	-	(1,346,938)
Total Retail	$ 45,567,427	$ -	$ -	$ -	$ -	$ 45,567,427

Notes:
(a) Revenues for Residential Rate R do not include credits issued to qualifying customers under the Residential Electric Assistance Program.
(b) Appendix 10, page 3 - Appendix 10, page 2
(c) For purposes of this calculation, all customers are assumed to receive service under the Energy Service rate.

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Report of Proposed Rate Changes
Percent Increase/(Decrease)

Tariff NHPUC No. 9

Date Filed: October 9, 2020
Date Effective: January 1, 2021

(A) Class	(B) Proposed Permanent Distribution (b)	(C) Current Transmission	(D) Current SCRC	(E) Current System Benefits	(F) Current Energy Service (c)	(G) Total Revenue
Residential Service Rate R (a)	13.7%	0.0%	0.0%	0.0%	0.0%	4.7%
General Service Rate G	13.7%	0.0%	0.0%	0.0%	0.0%	4.1%
Primary General Service Rate GV	13.7%	0.0%	0.0%	0.0%	0.0%	2.4%
Large General Service Rate LG	13.7%	0.0%	0.0%	0.0%	0.0%	2.0%
Outdoor Lighting Rates OL, EOL	-17.7%	0.0%	0.0%	0.0%	0.0%	-12.6%
Total Retail	13.0%	0.0%	0.0%	0.0%	0.0%	3.7%

Notes:
(a) Revenues for Residential Rate R do not include credits issued to qualifying customers under the Residential Electric Assistance Program.
(b) Percent change is Appendix 10, page 4, Column (B) / Appendix 10, page 2, Column (B)
(c) For purposes of this calculation, all customers are assumed to receive service under the Energy Service rate.

Distribution Revenue Allocation
Settlement Rate Year 1

Line			Source
11	Current Rate Distribution Revenue	$ 350,492.4	Col B Line 67
12	Current Streetlighting Revenue	$ 7,590.8	Col B Line 65
13	Current Distribution minus Streetlighting	$ 342,901.6	Line 11 - Line 12
15	Permanent Rate Revenue Adjustment	$ 44,986.7	See Settlement
16	Streetlighting Adjustment	$ (1,356.0)	Appendix 10, pages 25 & 26
17	Permanent Distribution Increase	$ 46,342.7	Line 15 - Line 16
19	Permanent Distribution Revenue	$ 395,479.1	Line 11 + Line 15
20	Adjusted Street Lighting Revenue	$ 6,234.8	Line 12 + Line 16
21	Permanent Distribution minus Streetlighting	$ 389,244.3	Line 19 - Line 20
23	Permanent Average Rate Change %	**13.51%**	(Line 21 / Line 13)
25	Temporary Rate Recoupment	$ 5,595.6	See Settlement
26	Customer Surcredit	(5,020.0)	See Settlement
27	Total Recoupment	575.6	Line 25 + Line 26
29	**Proposed Distribution Revenue**	**$ 396,054.7**	Line 19 + Line 27
31	Recoupment Average D Rate Change %	**0.15%**	(Line 29 / Line 19)

Line	Rate	A Test Year 2018 Billed Sales (MWh)	B Current Rate Distribution Revenue (Rev $000)	C = B * Line 23 Permanent D Change (Rev $000)	D = (B+C) * Line 31 Recoup D Change (Rev $000)	E = B + C + D Distribution Target (Rev $000)	F Proposed Rate Distribution (Rev $000)	G = F - B Difference Proposed vs Current (Rev $000)	H = G / A c/kWh	I = F / B % Chg.
39	R	3,144,509	$ 197,334.9	$ 26,669.548	$ 326.0	$ 224,330.4	$ 224,327.1			
40	R-TOD	462	34.6	4.7	0.1	39.4	39.1			
41		3,144,971	197,369.5	26,674.2	326.1	224,369.8	224,366.2	$ 26,996.7	0.858	13.68%
43	R-WH	92,916	4,195.3	567.0	6.9	4,769.2	4,522.9			
44	G-WH	3,379	136.8	18.5	0.2	155.5	147.3			
45	LCS-R	36,777	447.5	60.5	0.7	508.7	727.7			
46	LCS-G	4,510	28.9	3.9	0.0	32.8	68.9			
47		137,582	4,808.4	649.8	7.9	5,466.2	5,466.8	658.4	0.479	13.69%
49	G	1,715,822	83,771.9	11,321.7	138.4	95,231.9	95,231.3			
50	G-TOD	856	173.2	23.4	0.3	196.9	196.0			
51		1,716,678	83,945.1	11,345.1	138.7	95,428.8	95,427.4	11,482.3	0.669	13.68%
53	G-SH	5,452	201.7	27.3	0.3	229.3	229.3	27.6	0.506	13.67%
55	GV	1,665,676	36,211.5	4,893.9	59.8	41,165.3	41,170.4	4,958.9	0.298	13.69%
57	LG	1,172,439	18,846.4	2,547.1	31.1	21,424.6	21,430.4	2,584.0	0.220	13.71%
59	B-GV	2,778	214.6	29.0	0.4	243.9	242.1			
60	B-LG	80,345	1,304.4	176.3	2.2	1,482.8	1,483.4			
61		83,123	1,519.0	205.3	2.5	1,726.7	1,725.5	206.6	0.249	13.60%
63	EOL	11,371	3,081.8	(1,048.6)	3.0	2,036.2	2,036.2			
64	OL	17,130	4,509.0	(307.4)	6.1	4,207.7	4,207.7			
65		28,501	7,590.8	(1,356.0)	9.1	6,243.9	6,243.9	(1,346.9)	(4.726)	-17.74%
67	Total Retail	**7,954,422**	**$ 350,492.4**	**$ 44,986.7**	**$ 575.6**	**$ 396,054.7**	**$ 396,059.9**	$ 45,567.4	0.573	13.00%
69						Distribution Target	$ 396,054.7			
70						Difference	$ 5.2			

SUMMARY OF CURRENT AND PROPOSED DISTRIBUTION RATES

Rate	Blocks	Current Rates (01/01/18)	Current Rates (08/01/20)	Proposed Rates (01/01/21) (a)	Percent Change
R	Customer charge	$ 12.69	$ 13.81	$ 13.81	0.00%
	All KWH	0.04141	0.04508	0.04811	6.72%
Uncontrolled Water Heating	Meter charge	$ 4.47	$ 4.87	$ 4.87	0.00%
	All KWH	0.02030	0.02210	0.02161	-2.22%
Controlled Water Heating	Meter charge	$ 7.88	$ 8.58	$ 6.38	-25.64%
	All KWH	0.00120	0.00131	0.01141	770.99%
R-OTOD	Customer charge	$ 29.47	$ 32.08	$ 32.08	0.00%
	On-peak KWH	$ 0.13235	$ 0.14407	$ 0.14710	2.10%
	Off-peak KWH	0.00193	0.00210	0.00513	144.29%
G	Single phase customer charge	$ 14.89	$ 16.21	$ 16.21	0.00%
	Three phase customer charge	29.76	32.39	32.39	0.00%
	Load charge (over 5 KW)	$ 8.72	$ 9.49	$ 10.49	10.54%
	First 500 KWH	$ 0.06986	$ 0.07604	$ 0.02805	-63.11%
	Next 1,000 KWH	0.01731	0.01884	0.02268	20.38%
	All additional KWH	0.00612	0.00666	0.01709	156.61%
Space Heating	Meter charge	$ 2.98	$ 3.24	$ 3.24	0.00%
	All KWH	0.03426	0.03729	0.03908	4.80%
G-OTOD	Single phase customer charge	$ 38.57	$ 41.98	$ 41.98	0.00%
	Three phase customer charge	55.12	60.00	60.00	0.00%
	Load charge	$ 12.15	$ 13.23	$ 13.92	5.22%
	On-peak KWH	0.04901	0.05335	0.05335	0.00%
	Off-peak KWH	0.00768	0.00836	0.00836	0.00%
LCS	Radio-controlled option	$ 9.11	$ 9.92	$ 6.99	-29.54%
	8, 10 or 11-hour option	7.88	8.58	6.38	-25.64%
	Switch option	9.11	9.92	6.99	-29.54%
	Radio-controlled option	$ 0.00120	$ 0.00131	$ 0.01141	770.99%
	8-hour option	0.00120	0.00131	0.01141	770.99%
	10 or 11-hour option	0.02448	0.02665	0.02161	-18.91%

(a) Proposed rates include base change, recoupment and surcredit adjustment.

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020
Page 8 of 50

SUMMARY OF CURRENT AND PROPOSED DISTRIBUTION RATES

Rate	Blocks	Current Rates (01/01/18)	Current Rates (08/01/20)	Proposed Rates (01/01/21) (a)	Percent Change
GV	Customer charge	$ 194.03	$ 211.21	$ 211.21	0.00%
	First 100 KW	$ 5.58	$ 6.07	$ 6.48	6.75%
	All additional KW	5.34	5.81	6.22	7.06%
	First 200,000 KWH	$ 0.00606	$ 0.00660	$ 0.00657	-0.45%
	All additional KWH	0.00509	0.00554	0.00583	5.23%
	Minimum Charge	$ 893.00	$ 972.00	$ 1,015.00	4.42%
LG	Customer charge	$ 606.47	$ 660.15	$ 660.15	0.00%
	Demand charge	$ 4.75	$ 5.17	$ 5.51	6.58%
	On-peak KWH	$ 0.00508	$ 0.00553	$ 0.00554	0.18%
	Off-peak KWH	0.00429	0.00467	0.00468	0.21%
	Minimum Charge	$ 947.00	$ 1,031.00	$ 1,076.00	4.36%
	Discount for Service at 115kV	$ (0.43)	$ (0.47)	$ (0.49)	4.26%
B	Administrative charge	$ 341.84	$ 372.10	$ 372.10	0.00%
Service at	Translation charge	57.34	62.42	62.42	0.00%
less than					
115 KV	Demand charge	$ 4.48	$ 4.88	$ 5.12	4.92%
	All KWH	Energy charges in the standard rate			
B	Administrative charge	$ 341.84	$ 372.10	$ 372.10	0.00%
Service at	Translation charge	57.34	62.42	62.42	0.00%
115 KV					
or higher	Demand charge		Not applicable		
	All KWH		Not applicable		

(a) Proposed rates include base change, recoupment and surcredit adjustment.

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020

SUMMARY OF CURRENT AND PROPOSED DISTRIBUTION RATES

Outdoor Lighting Service Rate OL

	Lumens	Watts	Current Rates (01/01/18)	Current Rates (08/01/20)	Proposed Rates (01/01/21) (a)	Percent Change
For new and existing installations						
High Pressure Sodium	4,000	50	$ 15.83	$ 17.23	$ 14.77	-14.26%
	5,800	70	15.83	17.23	14.77	-14.26%
	9,500	100	21.05	22.91	19.64	-14.26%
	16,000	150	29.77	32.41	27.78	-14.28%
	30,000	250	30.51	33.21	28.47	-14.27%
	50,000	400	30.85	33.58	28.79	-14.27%
	130,000	1,000	49.51	53.89	46.20	-14.27%
Metal Halide	5,000	70	16.51	17.97	15.41	-14.26%
	8,000	100	22.60	24.60	21.09	-14.27%
	13,000	150	31.01	33.76	28.94	-14.28%
	13,500	175	31.67	34.37	29.55	-14.01%
	20,000	250	31.67	34.47	29.55	-14.26%
	36,000	400	31.96	34.79	29.82	-14.27%
	100,000	1,000	47.91	52.15	44.71	-14.27%
Light Emitting Diode (LED)	2,500	28			10.00	
	4,100	36			9.97	
	4,800	51			10.13	
	8,500	92			11.17	
	13,300	142			12.35	
	24,500	220			15.54	
For existing installations only						
Incandescent	600	105	9.12	9.93	8.51	-14.29%
	1,000	105	10.18	11.08	9.50	-14.26%
	2,500	205	13.06	14.22	12.19	-14.29%
	6,000	448	22.44	24.43	20.94	-14.28%
Mercury	3,500	100	13.96	15.20	13.03	-14.29%
	7,000	175	16.80	18.29	15.68	-14.28%
	11,000	250	20.77	22.61	19.38	-14.28%
	15,000	400	23.76	25.86	22.17	-14.26%
	20,000	400	25.65	27.92	23.94	-14.27%
	56,000	1,000	40.77	44.38	38.05	-14.27%
Fluorescent	20,000	330	34.79	37.87	32.47	-14.27%
High Pressure Sodium in existing mercury luminaires						
	12,000	150	21.77	23.70	20.32	-14.28%
	34,200	360	27.87	30.34	26.01	-14.28%

(a) Proposed rates include base change, recoupment and surcredit adjustment.

SUMMARY OF CURRENT AND PROPOSED DISTRIBUTION RATES

Energy Efficient Outdoor Lighting Service Rate EOL

	Lumens	Watts	Current Rates (01/01/18)	Current Rates (08/01/20)	Proposed Rates (01/01/21) (a)	Percent Change
High Pressure Sodium	4,000	50	$ 8.42	$ 9.17	$ 6.12	-33.25%
	5,800	70	8.42	9.17	6.43	-29.90%
	9,500	100	10.36	11.28	6.85	-39.26%
	16,000	150	11.39	12.40	7.51	-39.46%
	30,000	250	11.39	12.40	8.73	-29.57%
	50,000	400	11.76	12.80	10.44	-18.46%
	130,000	1,000	22.32	24.30	17.11	-29.59%
Metal Halide	5,000	70	8.75	9.52	6.45	-32.26%
	8,000	100	11.57	12.59	6.79	-46.09%
	13,000	150	12.35	13.44	7.52	-44.07%
	13,500	175	13.00	14.15	7.69	-45.68%
	20,000	250	13.22	14.39	8.55	-40.56%
	36,000	400	13.59	14.79	10.27	-30.58%
	100,000	1,000	24.21	26.35	16.93	-35.75%
LED's and other technologies accepted by the Company						
	Per fixture charge		3.37	3.67	3.01	-17.90%
	Per watt charge		$ 0.05130	$ 0.05580	$ 0.01058	-81.04%

(a) Proposed rates include base change, recoupment and surcredit adjustment.

Summary of Revenues by Type and Class

Current Revenues						
	Distribution	Transmission	SCRC	SBC	Energy	Total
Rate R	197,334,891	94,681,175	30,879,081	23,363,704	222,253,918	568,512,769
Rate R CWH	24,218	12,698	3,094	4,047	38,501	82,558
Rate R UWH	4,171,103	2,153,177	907,087	686,319	6,528,810	14,446,496
Rate R LCS	447,452	857,268	208,892	273,252	2,599,391	4,386,255
Rate R OTOD	34,646	10,678	3,895	3,429	32,620	85,268
Rate R	202,012,310	97,714,996	32,002,049	24,330,751	231,453,240	587,513,346
Rate G	83,771,868	48,826,887	15,361,851	12,748,559	121,274,312	281,983,477
Rate G CWH	-	-	-	-	-	-
Rate G UWH	136,750	78,771	31,225	25,108	238,849	510,703
Rate G LCS	28,868	105,125	23,993	33,508	318,758	510,252
Rate G Space	201,725	153,034	63,187	40,507	385,338	843,791
Rate G OTOD	173,196	55,301	8,334	6,360	60,499	303,690
Rate G	84,312,407	49,219,118	15,488,590	12,854,042	122,277,756	284,151,913
Rate GV	36,426,129	44,111,953	13,492,968	12,396,614	100,524,363	206,952,027
Rate LG	20,150,790	29,120,817	7,079,752	9,308,181	75,480,205	141,139,745
Rate OL/EOL	7,590,790	586,558	271,903	211,765	2,014,476	10,675,492
TOTAL	350,492,426	220,753,442	68,335,262	59,101,353	531,750,040	1,230,432,523

Proposed Revenues						
	Distribution	Transmission	SCRC	SBC	Energy	Total
Rate R	224,327,079	94,681,175	30,879,081	23,363,704	222,253,918	595,504,957
Rate R CWH	25,294	12,698	3,094	4,047	38,501	83,634
Rate R UWH	4,497,565	2,153,177	907,087	686,319	6,528,810	14,772,958
Rate R LCS	727,721	857,268	208,892	273,252	2,599,391	4,666,524
Rate R OTOD	39,112	10,678	3,895	3,429	32,620	89,734
Rate R	229,616,771	97,714,996	32,002,049	24,330,751	231,453,240	615,117,807
Rate G	95,231,333	48,826,887	15,361,851	12,748,559	121,274,312	293,442,942
Rate G CWH	-	-	-	-	-	-
Rate G UWH	147,275	78,771	31,225	25,108	238,849	521,228
Rate G LCS	68,906	105,125	23,993	33,508	318,758	550,290
Rate G Space	229,307	153,034	63,187	40,507	385,338	871,373
Rate G OTOD	196,029	55,301	8,334	6,360	60,499	326,523
Rate G	95,872,850	49,219,118	15,488,590	12,854,042	122,277,756	295,712,356
Rate GV	41,412,559	44,111,953	13,492,968	12,396,614	100,524,363	211,938,457
Rate LG	22,913,821	29,120,817	7,079,752	9,308,181	75,480,205	143,902,776
Rate OL/EOL	6,243,852	586,558	271,903	211,765	2,014,476	9,328,554
TOTAL	396,059,853	220,753,442	68,335,262	59,101,353	531,750,040	1,275,999,950

Source of data is Appendix 10, pages 12 through 21

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020
Page 12 of 50

Comparison of Current vs Proposed Permanent Rates

Rate R - Residential Electric Service

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Customer Charge							
Customer Charge	5,289,264	$ 12.69	$ 67,120,760	$ 13.81	$ 73,044,736	$ 5,923,976	8.83%
Energy Charge All kWh	3,144,509,315						
Distribution		$ 0.04141	$ 130,214,131	$ 0.04811	$ 151,282,343	$ 21,068,212	16.18%
Transmission		0.03011	94,681,175	0.03011	94,681,175	-	0.00%
Stranded Cost Recovery Charge		0.00982	30,879,081	0.00982	30,879,081	-	0.00%
System Benefits Charge		0.00743	23,363,704	0.00743	23,363,704	-	0.00%
Energy Service Charge		0.07068	222,253,918	0.07068	222,253,918	-	0.00%
Distribution Impact Only		$ 0.06276	$ 197,334,891	$ 0.07134	$ 224,327,079	$ 26,992,188	13.68%
Total Change		$ 0.18080	$ 568,512,769	$ 0.18938	$ 595,504,957	$ 26,992,188	4.75%

Rate R - Residential Uncontrolled Water Heating

	(A) Billing Determinants	(B) Current Rate	(C) Current Revenues	(D) Proposed Rate	(E) Proposed Revenues	(F) Difference	(G) % Chg
Customer Charge							
Customer Charge	513,638	$ 4.47	$ 2,295,964	$ 4.87	$ 2,501,419	$ 205,455	8.95%
Energy Charge All kWh	92,371,389						
Distribution		$ 0.02030	$ 1,875,139	$ 0.02161	$ 1,996,146	$ 121,007	6.45%
Transmission		0.02331	2,153,177	0.02331	2,153,177	-	0.00%
Stranded Cost Recovery Charge		0.00982	907,087	0.00982	907,087	-	0.00%
System Benefits Charge		0.00743	686,319	0.00743	686,319	-	0.00%
Energy Service Charge		0.07068	6,528,810	0.07068	6,528,810	-	0.00%
Distribution Impact Only		$ 0.04516	$ 4,171,103	$ 0.04869	$ 4,497,565	$ 326,462	7.83%
Total Change		$ 0.15640	$ 14,446,496	$ 0.15993	$ 14,772,958	$ 326,462	2.26%

Rate R - Residential Controlled Water Heating

	(A) Billing Determinants	(B) Current Rate	(C) Current Revenues	(D) Proposed Rate	(E) Proposed Revenues	(F) Difference	(G) % Chg
Customer Charge							
Customer Charge	2,990	$ 7.88	$ 23,564	$ 6.38	$ 19,079	$ (4,485)	-19.04%
Energy Charge All kWh	544,730						
Distribution		$ 0.00120	$ 654	$ 0.01141	$ 6,215	$ 5,561	850.83%
Transmission		0.02331	12,698	0.02331	12,698	-	0.00%
Stranded Cost Recovery Charge		0.00568	3,094	0.00568	3,094	-	0.00%
System Benefits Charge		0.00743	4,047	0.00743	4,047	-	0.00%
Energy Service Charge		0.07068	38,501	0.07068	38,501	-	0.00%
Distribution Impact Only		$ 0.04446	$ 24,218	$ 0.04643	$ 25,294	$ 1,076	4.44%
Total Change		$ 0.15156	$ 82,558	$ 0.15353	$ 83,634	$ 1,076	1.30%

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020
Page 13 of 50

Comparison of Current vs Proposed
Permanent Rates

Rate R - Load Control Service, Radio Controlled

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Customer Charge							
Customer Charge	41,348	$ 9.11	$ 376,678	$ 6.99	$ 289,020	$ (87,658)	-23.27%
Energy Charge All kWh	36,095,933						
Distribution		$ 0.00120	$ 43,315	$ 0.01141	$ 411,855	$ 368,540	850.83%
Transmission		0.02331	841,396	0.02331	841,396	-	0.00%
Stranded Cost Recovery Charge		0.00568	205,025	0.00568	205,025	-	0.00%
System Benefits Charge		0.00743	268,193	0.00743	268,193	-	0.00%
Energy Service Charge		0.07068	2,551,261	0.07068	2,551,261	-	0.00%
Distribution Impact Only		$ 0.01164	$ 419,993	$ 0.01942	$ 700,875	$ 280,882	66.88%
Total Change		$ 0.11874	$ 4,285,868	$ 0.12652	$ 4,566,750	$ 280,882	6.55%

Rate R - Load Control Service, 8 Hour Switch

	(A) Billing Determinants	(B) Current Rate	(C) Current Revenues	(D) Proposed Rate	(E) Proposed Revenues	(F) Difference	(G) % Chg
Customer Charge							
Customer Charge	145	$ 9.11	$ 1,316	$ 6.99	$ 1,010	$ (306)	-23.27%
Energy Charge All kWh	44,152						
Distribution		$ 0.00120	$ 53	$ 0.01141	$ 504	$ 451	850.83%
Transmission		0.02331	1,029	0.02331	1,029	-	0.00%
Stranded Cost Recovery Charge		0.00568	251	0.00568	251	-	0.00%
System Benefits Charge		0.00743	328	0.00743	328	-	0.00%
Energy Service Charge		0.07068	3,121	0.07068	3,121	-	0.00%
Distribution Impact Only		$ 0.03101	$ 1,369	$ 0.03429	$ 1,514	$ 145	10.59%
Total Change		$ 0.13811	$ 6,098	$ 0.14140	$ 6,243	$ 145	2.38%

Rate R - Load Control Service, 8 Hour No Switch

	(A) Billing Determinants	(B) Current Rate	(C) Current Revenues	(D) Proposed Rate	(E) Proposed Revenues	(F) Difference	(G) % Chg
Customer Charge							
Customer Charge	1,249	$ 7.88	$ 9,844	$ 6.38	$ 7,970	$ (1,874)	-19.04%
Energy Charge All kWh	357,451						
Distribution		$ 0.00120	$ 429	$ 0.01141	$ 4,079	$ 3,650	850.83%
Transmission		0.02331	8,332	0.02331	8,332	-	0.00%
Stranded Cost Recovery Charge		0.00568	2,030	0.00568	2,030	-	0.00%
System Benefits Charge		0.00743	2,656	0.00743	2,656	-	0.00%
Energy Service Charge		0.07068	25,265	0.07068	25,265	-	0.00%
Distribution Impact Only		$ 0.02874	$ 10,273	$ 0.03371	$ 12,049	$ 1,776	17.29%
Total Change		$ 0.13584	$ 48,556	$ 0.14081	$ 50,332	$ 1,776	3.66%

Rate R - Load Control Service, 10/11 Hour Switch

	(A) Billing Determinants	(B) Current Rate	(C) Current Revenues	(D) Proposed Rate	(E) Proposed Revenues	(F) Difference	(G) % Chg
Customer Charge							
Customer Charge	60	$ 9.11	$ 547	$ 6.99	$ 419	$ (128)	-23.27%
Energy Charge All kWh	13,784						
Distribution		$ 0.02448	$ 337	$ 0.02161	$ 298	$ (39)	-11.72%
Transmission		0.02331	321	0.02331	321	-	0.00%
Stranded Cost Recovery Charge		0.00568	78	0.00568	78	-	0.00%
System Benefits Charge		0.00743	102	0.00743	102	-	0.00%
Energy Service Charge		0.07068	974	0.07068	974	-	0.00%
Distribution Impact Only		$ 0.06413	$ 884	$ 0.05202	$ 717	$ (167)	-18.89%
Total Change		$ 0.17114	$ 2,359	$ 0.15902	$ 2,192	$ (167)	-7.08%

Rate R - Load Control Service, 10/11 Hour No Switch

	(A) Billing Determinants	(B) Current Rate	(C) Current Revenues	(D) Proposed Rate	(E) Proposed Revenues	(F) Difference	(G) % Chg
Customer Charge							
Customer Charge	1,070	$ 7.88	$ 8,432	$ 6.38	$ 6,827	$ (1,605)	-19.04%
Energy Charge All kWh	265,564						
Distribution		$ 0.02448	$ 6,501	$ 0.02161	$ 5,739	$ (762)	-11.72%
Transmission		0.02331	6,190	0.02331	6,190	-	0.00%
Stranded Cost Recovery Charge		0.00568	1,508	0.00568	1,508	-	0.00%
System Benefits Charge		0.00743	1,973	0.00743	1,973	-	0.00%
Energy Service Charge		0.07068	18,770	0.07068	18,770	-	0.00%
Distribution Impact Only		$ 0.05623	$ 14,933	$ 0.04732	$ 12,566	$ (2,367)	-15.85%
Total Change		$ 0.16333	$ 43,374	$ 0.15441	$ 41,007	$ (2,367)	-5.46%

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020
Page 14 of 50

Comparison of Current vs Proposed
Permanent Rates

Rate R - Optional Time of Day

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Customer Charge							
Customer Charge	466	$ 29.47	$ 13,721	$ 32.08	$ 14,936	$ 1,215	8.86%
Energy Charge On Peak kWh	153,613						
Distribution		$ 0.13235	$ 20,331	$ 0.14710	$ 22,596	$ 2,265	11.14%
Transmission		0.03011	4,625	0.03011	4,625	-	0.00%
Stranded Cost Recovery Charge		0.00844	1,296	0.00844	1,296	-	0.00%
System Benefits Charge		0.00743	1,141	0.00743	1,141	-	0.00%
Energy Service Charge		0.07068	10,857	0.07068	10,857	-	0.00%
Energy Charge Off Peak kWh	307,907						
Distribution		$ 0.00193	$ 594	$ 0.00513	$ 1,580	$ 986	165.99%
Transmission		0.01966	6,053	0.01966	6,053	-	0.00%
Stranded Cost Recovery Charge		0.00844	2,599	0.00844	2,599	-	0.00%
System Benefits Charge		0.00743	2,288	0.00743	2,288	-	0.00%
Energy Service Charge		0.07068	21,763	0.07068	21,763	-	0.00%
Distribution Impact Only		$ 0.07507	$ 34,646	$ 0.08475	$ 39,112	$ 4,466	12.89%
Total Change		$ 0.18475	$ 85,268	$ 0.19443	$ 89,734	$ 4,466	5.24%

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020
Page 15 of 50

Comparison of Current vs Proposed
Permanent Rates

Rate G - General Service

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Customer Charge							
Customer Charge 1 Phase	682,271	$ 14.89	$ 10,159,015	$ 16.21	$ 11,059,613	900,598	8.87%
Customer Charge 3 Phase	235,118	29.76	6,997,118	32.39	7,615,478	618,360	8.84%
Demand Charge >5 kW	4,060,918						
Distribution		$ 8.72	$ 35,411,205	$ 10.49	$ 42,599,030	7,187,825	20.30%
Transmission		7.77	31,553,333	7.77	31,553,333	-	0.00%
Stranded Cost Recovery Charge		0.69	2,802,033	0.69	2,802,033	-	0.00%
Energy Charge < 500 kWh	273,389,497						
Distribution		$ 0.06986	$ 19,098,990	$ 0.02805	$ 7,668,575	(11,430,415)	-59.85%
Transmission		0.02807	7,674,043	0.02807	7,674,043	-	0.00%
Stranded Cost Recovery Charge		0.00732	2,001,211	0.00732	2,001,211	-	0.00%
System Benefits Charge		0.00743	2,031,284	0.00743	2,031,284	-	0.00%
Energy Service Charge		0.07068	19,323,170	0.07068	19,323,170	-	0.00%
Energy Charge 501 - 1500 kWh	292,926,918						
Distribution		$ 0.01731	$ 5,070,565	$ 0.02268	$ 6,643,583	1,573,018	31.02%
Transmission		0.01056	3,093,308	0.01056	3,093,308	-	0.00%
Stranded Cost Recovery Charge		0.00732	2,144,225	0.00732	2,144,225	-	0.00%
System Benefits Charge		0.00743	2,176,447	0.00743	2,176,447	-	0.00%
Energy Service Charge		0.07068	20,704,075	0.07068	20,704,075	-	0.00%
Energy Charge >1500 kWh	1,149,505,765					-	
Distribution		$ 0.00612	7,034,975	$ 0.01709	19,645,054	12,610,079	179.25%
Transmission		0.00566	6,506,203	0.00566	6,506,203	-	0.00%
Stranded Cost Recovery Charge		0.00732	8,414,382	0.00732	8,414,382	-	0.00%
System Benefits Charge		0.00743	8,540,828	0.00743	8,540,828	-	0.00%
Energy Service Charge		0.07068	81,247,067	0.07068	81,247,067	-	0.00%
Distribution Impact Only		$ 0.04882	83,771,868	$ 0.05550	$ 95,231,333	$ 11,459,465	13.68%
Total Change		$ 0.16434	281,983,477	$ 0.17102	$293,442,942	$ 11,459,465	4.06%

Comparison of Current vs Proposed
Permanent Rates

Rate G - General Service Uncontrolled Water Heating

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Customer Charge							
Customer Charge	15,246	$ 4.47	$ 68,150	$ 4.87	$ 74,248	$ 6,098	8.95%
Energy Charge All kWh	3,379,300						
Distribution		$ 0.02030	$ 68,600	$ 0.02161	$ 73,027	$ 4,427	6.45%
Transmission		0.02331	78,771	0.02331	78,771	-	0.00%
Stranded Cost Recovery Charge		0.00924	31,225	0.00924	31,225	-	0.00%
System Benefits Charge		0.00743	25,108	0.00743	25,108	-	0.00%
Energy Service Charge		0.07068	238,849	0.07068	238,849	-	0
Distribution Impact Only		$ 0.04047	$ 136,750	$ 0.04358	$ 147,275	$ 10,525	7.70%
Total Change		$ 0.15113	$ 510,703	$ 0.15424	$ 521,228	$ 10,525	2.06%

Rate G - General Service Controlled Water Heating

	(A) Billing Determinants	(B) Current Rate	(C) Current Revenues	(D) Proposed Rate	(E) Proposed Revenues	(F) Difference	(G) % Chg
Customer Charge							
Customer Charge	-	$ 7.88	$ -	$ 6.38	$ -	$ -	-19.04%
Energy Charge All kWh	-						
Distribution		$ 0.00120	$ -	$ 0.01141	$ -	$ -	850.83%
Transmission		0.02331	-	0.02331	-	-	0.00%
Stranded Cost Recovery Charge		0.00532	-	0.00532	-	-	0.00%
System Benefits Charge		0.00743	-	0.00743	-	-	0.00%
Energy Service Charge		0.07068	-	0.07068	-	-	0.00%
Distribution Impact Only			$ -		$ -	$ -	
Total Change			$ -		$ -	$ -	

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020
Page 17 of 50

Comparison of Current vs Proposed
Permanent Rates

Rate G - Space Heating

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Customer Charge							
Customer Charge	5,015	$ 2.98	$ 14,944	$ 3.24	$ 16,248	$ 1,304	8.72%
Energy Charge All kWh	5,451,861						
Distribution		$ 0.03426	$ 186,781	$ 0.03908	$ 213,059	$ 26,278	14.07%
Transmission		0.02807	153,034	0.02807	153,034	-	0.00%
Stranded Cost Recovery Charge		0.01159	63,187	0.01159	63,187	-	0.00%
System Benefits Charge		0.00743	40,507	0.00743	40,507	-	0.00%
Energy Service Charge		0.07068	385,338	0.07068	385,338	-	0.00%
Distribution Impact Only		$ 0.03700	$ 201,725	$ 0.04206	$ 229,307	$ 27,582	13.67%
Total		$ 0.15477	$ 843,791	$ 0.15983	$ 871,373	$ 27,582	3.27%

Rate G - Optional Time of Day

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Customer Charge							
Customer Charge 1 Phase	199	$ 38.57	$ 7,675	$ 41.98	$ 8,354	$ 679	8.84%
Customer Charge 3 Phase	261	55.12	14,364	60.00	15,636	1,272	8.85%
Demand Charge	10,801						
Distribution		$ 12.15	$ 131,232	$ 13.92	$ 150,350	$ 19,118	14.57%
Transmission		5.12	55,301	5.12	55,301	-	0.00%
Stranded Cost Recovery Charge		0.35	3,780	0.35	3,780	-	0.00%
Energy Charge On Peak kWh	323,044						
Distribution		$ 0.04901	$ 15,832	$ 0.05335	$ 17,234	$ 1,402	8.86%
Transmission		-	-	-	-	-	
Stranded Cost Recovery Charge		0.00532	1,719	0.00532	1,719	-	0.00%
System Benefits Charge		0.00743	2,400	0.00743	2,400	-	0.00%
Energy Service Charge		0.07068	22,833	0.07068	22,833	-	0.00%
Energy Charge Off Peak kWh	532,915						
Distribution		$ 0.00768	$ 4,093	$ 0.00836	$ 4,455	$ 362	8.85%
Transmission		-	-	-	-	-	
Stranded Cost Recovery Charge		0.00532	2,835	0.00532	2,835	-	0.00%
System Benefits Charge		0.00743	3,960	0.00743	3,960	-	0.00%
Energy Service Charge		0.07068	37,666	0.07068	37,666	-	0.00%
Distribution Impact Only		$ 0.20234	$ 173,196	$ 0.22902	$ 196,029	$ 22,833	13.18%
Total Change		$ 0.35480	$ 303,690	$ 0.38147	$ 326,523	$ 22,833	7.52%

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020

Comparison of Current vs Proposed
Permanent Rates

Rate G - Load Control Service, Radio Controlled

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Customer Charge							
Customer Charge	2,298	$ 9.11	$ 20,935	$ 6.99	$ 16,063	$ (4,872)	-23.27%
Energy Charge All kWh	4,365,538						
Distribution		$ 0.00120	$ 5,239	$ 0.01141	$ 49,811	$ 44,572	850.83%
Transmission		0.02331	101,761	0.02331	101,761	-	0.00%
Stranded Cost Recovery Charge		0.00532	23,225	0.00532	23,225	-	0.00%
System Benefits Charge		0.00743	32,436	0.00743	32,436	-	0.00%
Energy Service Charge		0.07068	308,556	0.07068	308,556	-	0.00%
Distribution Impact Only		$ 0.00600	$ 26,174	$ 0.01509	$ 65,874	$ 39,700	151.68%
Total Change		$ 0.11274	$ 492,152	$ 0.12183	$ 531,852	$ 39,700	8.07%

Rate G - Load Control Service, 8 Hour No Switch

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Customer Charge							
Customer Charge	72	$ 7.88	$ 567	$ 6.38	$ 459	$ (108)	-19.04%
Energy Charge All kWh	68,521						
Distribution		$ 0.00120	$ 82	$ 0.01141	$ 782	$ 700	850.83%
Transmission		0.02331	1,597	0.02331	1,597	-	0.00%
Stranded Cost Recovery Charge		0.00532	365	0.00532	365	-	0.00%
System Benefits Charge		0.00743	509	0.00743	509	-	0.00%
Energy Service Charge		0.07068	4,843	0.07068	4,843	-	0.00%
Distribution Impact Only		$ 0.00947	$ 649	$ 0.01811	$ 1,241	$ 592	91.22%
Total Change		$ 0.11621	$ 7,963	$ 0.12485	$ 8,555	$ 592	7.43%

Rate G - Load Control Service, 8 Hour Switch

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Customer Charge							
Customer Charge	0	$ 9.11	$ -	$ 6.99	$ -	$ -	-23.27%
Energy Charge All kWh	0						
Distribution		$ 0.00120	$ -	$ 0.01141	$ -	$ -	850.83%
Transmission		$ 0.02331	-	$ 0.02331	-	-	0.00%
Stranded Cost Recovery Charge		$ 0.00532	-	$ 0.00532	-	-	0.00%
System Benefits Charge		$ 0.00743	-	$ 0.00743	-	-	0.00%
Energy Service Charge		$ 0.07068	-	$ 0.07068	-	-	0.00%
Distribution Impact Only			$ -		$ -	$ -	
Total Change			$ -		$ -	$ -	

Rate G - Load Control Service, 10/11 Hour Switch

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Customer Charge							
Customer Charge	0	$ 9.11	$ -	$ 6.99	$ -	$ -	-23.27%
Energy Charge All kWh	0						
Distribution		$ 0.02448	$ -	$ 0.02161	$ -	$ -	-11.72%
Transmission		$ 0.02331	-	$ 0.02331	-	-	0.00%
Stranded Cost Recovery Charge		$ 0.00532	-	$ 0.00532	-	-	0.00%
System Benefits Charge		$ 0.00743	-	$ 0.00743	-	-	0.00%
Energy Service Charge		$ 0.07068	-	$ 0.07068	-	-	0.00%
Distribution Impact Only			$ -		$ -	$ -	
Total Change			$ -		$ -	$ -	

Rate G - Load Control Service, 10/11 Hour No Switch

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Customer Charge							
Customer Charge	24	$ 7.88	$ 189	$ 6.38	$ 153	$ (36)	-19.04%
Energy Charge All kWh	75,820						
Distribution		$ 0.02448	$ 1,856	$ 0.02161	$ 1,638	$ (218)	-11.72%
Transmission		0.02331	1,767	$ 0.02331	1,767	-	0.00%
Stranded Cost Recovery Charge		0.00532	403	$ 0.00532	403	-	0.00%
System Benefits Charge		0.00743	563	$ 0.00743	563	-	0.00%
Energy Service Charge		0.07068	5,359	$ 0.07068	5,359	-	0.00%
Distribution Impact Only		$ 0.02697	$ 2,045	$ 0.02362	$ 1,791	$ (254)	-12.42%
Total Change		$ 0.13370	$ 10,137	$ 0.13035	$ 9,883	$ (254)	-2.51%

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020
Page 19 of 50

Comparison of Current vs Proposed
Permanent Rates

Rate GV

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Customer Charge							
Customer Charge	16,601	$ 194.03	$ 3,221,053	$ 211.21	$ 3,506,255	$ 285,202	8.85%
Demand 1-100 kW	1,568,428						
Distribution		$ 5.58	$ 8,751,828	$ 6.48	$ 10,163,413	$ 1,411,585	16.13%
Transmission		10.40	16,311,651	$ 10.40	16,311,651	-	0.00%
Stranded Cost Recovery Charge		0.65	1,019,478	$ 0.65	1,019,478	-	0.00%
Demand > 100 kW	2,667,694						
Distribution		$ 5.34	$ 14,245,486	$ 6.22	$ 16,593,057	$ 2,347,571	16.48%
Transmission		10.40	27,744,018	10.40	27,744,018	-	0.00%
Stranded Cost Recovery Charge		0.65	1,734,001	0.65	1,734,001	-	0.00%
Minimum Charge	123	$ 893.00	$ 110,064	$ 1,015.00	$ 125,101	$ 15,037	13.66%
Energy Charge 1 - 200,000 kWh	1,448,276,753						
Distribution		$ 0.00606	$ 8,776,557	$ 0.00657	$ 9,515,178	$ 738,621	8.42%
Transmission		-	-	-	-	-	
Stranded Cost Recovery Charge		0.00643	9,312,420	0.00643	9,312,420	-	0.00%
System Benefits Charge		0.00743	10,760,696	0.00743	10,760,696	-	0.00%
Energy Service Charge		0.06025	87,258,674	0.06025	87,258,674	-	0.00%
Energy Charge >200,000 kWh	217,399,074						
Distribution		$ 0.00509	$ 1,106,561	$ 0.00583	$ 1,267,437	$ 160,876	14.54%
Transmission		-	-	-	-	-	
Stranded Cost Recovery Charge		0.00643	1,397,876	0.00643	1,397,876	-	0.00%
System Benefits Charge		0.00743	1,615,275	0.00743	1,615,275	-	0.00%
Energy Service Charge		0.06025	13,098,294	0.06025	13,098,294	-	0.00%
Distribution Impact Only		$ 0.02174	$ 36,211,549	$ 0.02472	$ 41,170,441	$ 4,958,892	13.69%
Total Change		$ 0.12395	$206,463,932	$ 0.12693	$211,422,824	$ 4,958,892	2.40%

Rate GV - Backup Service < 115 KV

	(A) Billing Determinants	(B) Current Rate	(C) Current Revenues	(D) Proposed Rate	(E) Proposed Revenues	(F) Difference	(G) % Chg
Administrative Charge	108	$ 341.84	$ 36,919	$ 372.10	$ 40,187	$ 3,268	8.85%
Translation Charge	39	$ 57.34	$ 2,236	62.42	$ 2,434	$ 198	8.86%
Demand Charge	35,399						
Distribution		$ 4.48	$ 158,588	$ 5.12	$ 181,243	$ 22,655	14.29%
Transmission		1.59	56,284	1.59	56,284	-	0.00%
Stranded Cost Recovery Charge		0.32	11,328	0.32	11,328	-	0.00%
Energy Charge 1 - 200,000 kWh	2,778,333						
Distribution		$ 0.00606	$ 16,837	$ 0.00657	$ 18,254	$ 1,417	8.42%
Transmission		-	-	$ -	-	-	
Stranded Cost Recovery Charge		0.00643	17,865	$ 0.00643	17,865	-	0.00%
System Benefits Charge		0.00743	20,643	$ 0.00743	20,643	-	0.00%
Energy Service Charge		0.06025	167,395	$ 0.06025	167,395	-	0.00%
Energy Charge >200,000 kWh	0						
Distribution		$ 0.00509	$ -	$ 0.00583	$ -	$ -	14.54%
Transmission		-	-	$ -	-	-	
Stranded Cost Recovery Charge		0.00643	-	$ 0.00643	-	-	0.00%
System Benefits Charge		0.00743	-	$ 0.00743	-	-	0.00%
Energy Service Charge		0.06025	-	$ 0.06025	-	-	0.00%
Distribution Impact Only		$ 0.07723	$ 214,580	$ 0.08715	$ 242,118	$ 27,538	12.83%
Total Change		$ 0.17568	$ 488,095	$ 0.18559	$ 515,633	$ 27,538	5.64%

Rate GV - Backup Service > 115 KV

	(A) Billing Determinants	(B) Current Rate	(C) Current Revenues	(D) Proposed Rate	(E) Proposed Revenues	(F) Difference	(G) % Chg
Administrative Charge	-	$ 341.84	$ -	$ 372.10	$ -	$ -	8.85%
Translation Charge	-	$ 57.34	$ -	62.42	$ -	$ -	8.86%
Demand Charge	-						
Transmission		1.59	-	1.59	-	-	0.00%
Stranded Cost Recovery Charge		0.32	-	0.32	-	-	0.00%
Energy Charge On Peak	-						
Transmission		-	-	-	-	-	0.00%
Stranded Cost Recovery Charge		0.00256	-	0.00256	-	-	0.00%
System Benefits Charge		0.00586	-	0.00586	-	-	0.00%
Energy Service Charge		0.12222	-	0.12222	-	-	0.00%
Energy Charge Off Peak	-						
Transmission		-	-	-	-	-	0.00%
Stranded Cost Recovery Charge		0.00171	-	0.00171	-	-	0.00%
System Benefits Charge		0.00586	-	0.00586	-	-	0.00%
Energy Service Charge		0.12222	-	0.12222	-	-	0.00%
Distribution Impact Only		$ -	$ -	$ -	$ -	$ -	
Total Change		$ -	$ -	$ -	$ -	$ -	

Comparison of Current vs Proposed
Permanent Rates

Rate LG

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Customer Charge							
Customer Charge	1,272	$ 606.47	$ 771,430	$ 660.15	$ 839,711	$ 68,281	8.85%
Demand	2,661,538						
Distribution		$ 4.75	$ 12,642,306	$ 5.51	$ 14,665,074	$ 2,022,768	16.00%
Transmission		10.24	27,254,149	10.24	27,254,149	-	0.00%
Stranded Cost Recovery Charge		0.49	1,304,154	0.49	1,304,154	-	0.00%
Minimum Charge	0	$ 947.00	$ -	$ 1,076.00	$ -	$ -	13.62%
Discount for above 115kV	0	$ (0.43)	$ -	$ (0.49)	$ -	$ -	13.95%
Energy Charge On Peak	510,025,661						
Distribution		$ 0.00508	$ 2,590,930	$ 0.00554	$ 2,825,542	$ 234,612	9.06%
Transmission		-	-	-	-	-	0.00%
Stranded Cost Recovery Charge		0.00519	2,647,033	0.00519	2,647,033	-	0.00%
System Benefits Charge		0.00743	3,789,491	0.00743	3,789,491	-	0.00%
Energy Service Charge		0.06025	30,729,046	0.06025	30,729,046	-	0.00%
Energy Charge Off Peak	662,413,106						
Distribution		$ 0.00429	$ 2,841,752	$ 0.00468	$ 3,100,093	$ 258,341	9.09%
Transmission		-	-	-	-	-	0.00%
Stranded Cost Recovery Charge		0.00378	2,503,922	0.00378	2,503,922	-	0.00%
System Benefits Charge		0.00743	4,921,729	0.00743	4,921,729	-	0.00%
Energy Service Charge		0.06025	39,910,390	0.06025	39,910,390	-	0.00%
Distribution Impact Only		$ 0.01607	$ 18,846,418	$ 0.01828	$ 21,430,420	$ 2,584,002	13.71%
Total Charge		$ 0.11251	$131,906,332	$ 0.11471	$134,490,334	$ 2,584,002	1.96%

Rate LG - Backup Service < 115 KV

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Administrative Charge	109	$ 341.84	$ 37,329	$ 372.10	$ 40,633	$ 3,304	8.85%
Translation Charge	26	$ 57.34	$ 1,491	62.42	$ 1,623	$ 132	8.86%
Demand Charge	260,477						
Distribution		$ 4.48	$ 1,166,937	$ 5.12	$ 1,333,642	$ 166,705	14.29%
Transmission		1.59	414,158	1.59	414,158	-	0.00%
Stranded Cost Recovery Charge		0.24	62,514	0.24	62,514	-	0.00%
Energy Charge On Peak	6,651,595						
Distribution		$ 0.00508	$ 33,790	$ 0.00554	$ 36,850	$ 3,060	9.06%
Transmission		-	-	-	-	-	0.00%
Stranded Cost Recovery Charge		0.00519	34,522	0.00519	34,522	-	0.00%
System Benefits Charge		0.00743	49,421	0.00743	49,421	-	0.00%
Energy Service Charge		0.06025	400,759	0.06025	400,759	-	0.00%
Energy Charge Off Peak	8,704,697						
Distribution		$ 0.00429	$ 37,343	$ 0.00468	$ 40,738	$ 3,395	9.09%
Transmission		-	-	-	-	-	0.00%
Stranded Cost Recovery Charge		0.00378	32,904	0.00378	32,904	-	0.00%
System Benefits Charge		0.00743	64,676	0.00743	64,676	-	0.00%
Energy Service Charge		0.06025	524,458	0.06025	524,458	-	0.00%
Distribution Impact Only		$ 0.08315	$ 1,276,890	$ 0.09465	$ 1,453,486	$ 176,596	13.83%
Total Charge		$ 0.18626	$ 2,860,302	$ 0.19776	$ 3,036,898	$ 176,596	6.17%

Rate LG - Backup Service > 115 KV

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Administrative Charge	80	$ 341.84	$ 27,482	$ 372.10	$ 29,915	$ 2,433	8.85%
Translation Charge	-	$ 57.34	$ -	62.42	$ -	$ -	8.86%
Demand Charge	913,528						
Transmission		1.59	$ 1,452,510	1.59	$ 1,452,510	-	0.00%
Stranded Cost Recovery Charge		0.24	219,247	0.24	219,247	-	0.00%
Energy Charge On Peak	21,134,611						
Transmission		-	$ -	-	$ -	-	0.00%
Stranded Cost Recovery Charge		0.00519	109,689	0.00519	109,689	-	0.00%
System Benefits Charge		0.00743	157,030	0.00743	157,030	-	0.00%
Energy Service Charge		0.06025	1,273,360	0.06025	1,273,360	-	0.00%
Energy Charge Off Peak	43,853,801						
Transmission		-	$ -	-	$ -	-	0.00%
Stranded Cost Recovery Charge		0.00378	165,767	0.00378	165,767	-	0.00%
System Benefits Charge		0.00743	325,834	0.00743	325,834	-	0.00%
Energy Service Charge		0.06025	2,642,192	0.06025	2,642,192	-	0.00%
Distribution Impact Only		$ 0.00042	$ 27,482	$ 0.00046	$ 29,915	$ 2,433	8.85%
Total Charge		$ 0.09807	$ 6,373,111	$ 0.09810	$ 6,375,544	$ 2,433	0.04%

Comparison of Current vs Proposed
Permanent Rates

Rate OL - Outdoor Lighting

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Energy Charge All kWh	17,130,466						
Transmission		$ 0.02058	$ 352,545	$ 0.02058	$ 352,545	$ -	0.00%
Stranded Cost Recovery Charge		0.00954	163,425	0.00954	163,425	-	0.00%
System Benefits Charge		0.00743	127,279	0.00743	127,279	-	0.00%
Energy Service Charge		0.07068	1,210,781	0.07068	1,210,781	-	0.00%
Total		$ 0.10823	$ 1,854,030	$ 0.10823	$ 1,854,030	$ -	0.00%
Distribution Charge (per fixture)							
4000 LUMEN HP SODIUM	42,792	$ 15.83	$ 677,397	$ 14.77	$ 632,137	$ (45,260)	-6.68%
5800 LUMEN HP SODIUM	7,260	15.83	114,926	14.77	107,247	(7,679)	-6.68%
9500 LUMEN HP SODIUM	10,692	21.05	225,067	19.64	210,029	(15,038)	-6.68%
16000 LUMEN HP SODIUM	9,936	29.77	295,795	27.78	276,031	(19,764)	-6.68%
30000 LUMEN HP SODIUM	15,480	30.51	472,295	28.47	440,738	(31,557)	-6.68%
50000 LUMEN HP SODIUM	22,860	30.85	705,231	28.79	658,111	(47,120)	-6.68%
130000 LUMEN HP SODIUM	3,684	49.51	182,395	46.20	170,208	(12,187)	-6.68%
5000 LUMEN METAL HALIDE	2,700	16.51	44,577	15.41	41,599	(2,978)	-6.68%
8000 LUMEN METAL HALIDE	1,608	22.60	36,341	21.09	33,913	(2,428)	-6.68%
13000 LUMEN METAL HALIDE	-	31.01	-	28.94	-	-	-6.68%
13500 LUMEN METAL HALIDE	1,464	31.67	46,365	29.55	43,267	(3,098)	-6.68%
20000 LUMEN METAL HALIDE	3,696	31.67	117,052	29.55	109,231	(7,821)	-6.68%
36000 LUMEN METAL HALIDE	5,136	31.96	164,147	29.82	153,179	(10,968)	-6.68%
100000 LUMEN METAL HALIDE	3,216	47.91	154,079	44.71	143,784	(10,295)	-6.68%
600 LUMEN INCANDESCENT	1,068	9.12	9,740	8.51	9,089	(651)	-6.68%
1000 LUMEN INCANDESCENT	2,844	10.18	28,952	9.50	27,017	(1,935)	-6.68%
2500 LUMEN INCANDESCENT	48	13.06	627	12.19	585	(42)	-6.70%
6000 LUMEN INCANDESCENT	-	22.44	-	20.94	-	-	-6.68%
3500 LUMEN MERCURY	59,064	13.96	824,533	13.03	769,442	(55,091)	-6.68%
7000 LUMEN MERCURY	11,472	16.80	192,730	15.68	179,852	(12,878)	-6.68%
11000 LUMEN MERCURY	684	20.77	14,207	19.38	13,257	(950)	-6.69%
15000 LUMEN MERCURY	36	23.76	855	22.17	798	(57)	-6.67%
20000 LUMEN MERCURY	5,088	25.65	130,507	23.94	121,787	(8,720)	-6.68%
56000 LUMEN MERCURY	1,632	40.77	66,537	38.05	62,091	(4,446)	-6.68%
20000 LUMEN FLUORESCENT	24	34.79	835	32.47	779	(56)	-6.71%
12000 LUMEN HP SODIUM	96	21.77	2,090	20.32	1,950	(140)	-6.70%
34200 LUMEN HP SODIUM	60	27.87	1,672	26.01	1,560	(112)	-6.70%
Average Number of Fixtures/Month	17,720						
Distribution Impact Only		$ 0.26321	$ 4,508,952	$ 0.24563	$ 4,207,681	$ (301,271)	-6.68%
Total Charge		$ 0.37144	$ 6,362,982	$ 0.35386	$ 6,061,711	$ (301,271)	-4.73%

Rate EOL - Efficient Outdoor Lighting

	(A) Billing Determinants	(B) Current Rate	(C) = (A) x (B) Current Revenues	(D) Proposed Rate	(E) = (A) x (D) Proposed Revenues	(F) = (E) - (C) Proposed vs. Current Difference	(G) = (F) / (C) Proposed vs. Current % Chg
Energy Charge All kWh	11,370,898						
Transmission		$ 0.02058	$ 234,013	$ 0.02058	$ 234,013	$ -	0.00%
Stranded Cost Recovery Charge		0.00954	108,478	$ 0.00954	108,478	-	0.00%
System Benefits Charge		0.00743	84,486	$ 0.00743	84,486	-	0.00%
Energy Service Charge		0.07068	803,695	$ 0.07068	803,695	-	0.00%
Total			$ 1,230,672		$ 1,230,672	$ -	0.00%
Distribution Charge (per fixture)							
4000 LUMEN HP SODIUM	45,216	$ 8.42	$ 380,719	$ 6.12	$ 276,779	$ (103,940)	-27.30%
5800 LUMEN HP SODIUM	2,616	8.42	22,027	6.43	16,816	(5,211)	-23.66%
9500 LUMEN HP SODIUM	4,272	10.36	44,258	6.85	29,268	(14,990)	-33.87%
16000 LUMEN HP SODIUM	6,648	11.39	75,721	7.51	49,905	(25,816)	-34.09%
30000 LUMEN HP SODIUM	20,784	11.39	236,730	8.73	181,523	(55,207)	-23.32%
50000 LUMEN HP SODIUM	1,584	11.76	18,628	10.44	16,532	(2,096)	-11.25%
130000 LUMEN HP SODIUM	684	22.32	15,267	17.11	11,704	(3,563)	-23.34%
5000 LUMEN METAL HALIDE	9,984	8.75	87,360	6.45	64,388	(22,972)	-26.30%
8000 LUMEN METAL HALIDE	1,152	11.57	13,329	6.79	7,819	(5,510)	-41.34%
13000 LUMEN METAL HALIDE	-	12.35	-	7.52	-	-	-39.13%
13500 LUMEN METAL HALIDE	1,056	13.00	13,728	7.69	8,117	(5,611)	-40.87%
20000 LUMEN METAL HALIDE	840	13.22	11,105	8.55	7,185	(3,920)	-35.30%
36000 LUMEN METAL HALIDE	528	13.59	7,176	10.27	5,421	(1,755)	-24.46%
100000 LUMEN METAL HALIDE	1,236	24.21	29,924	16.93	20,927	(8,997)	-30.07%
LEDs	388,872	3.37	1,310,499	3.01	1,171,676	(138,823)	-10.59%
Average Number of Fixtures/Month	40,456						
Distribution Charge (per Watt)							
LEDs	15,894,084	$ 0.05130	$ 815,367	$ 0.01058	$ 168,111	$ (647,256)	-79.38%
Distribution Impact Only		$ 0.27103	$ 3,081,838	$ 0.17907	$ 2,036,171	$ (1,045,667)	-33.93%
Total Charge		$ 0.37926	$ 4,312,510	$ 0.28730	$ 3,266,843	$ (1,045,667)	-24.25%

STREET LIGHTING DISTRIBUTION RATE DESIGN

Distribution Breakout by Component

	Rate EOL		Rate OL	
Total Fixtures	A	40,456	E	17,720
	Aa - Non-LED	8,050	Ea - Non-LED	17,720
	Ab - LED	32,406	Eb - LED	-
Connected Demand KW	B	2,619	F	3,947
Annual kWh	C	11,370,898	G	17,130,466
Proposed Distribution Revenue	D	$ 2,036,170	H	$ 4,207,682
Distribution by Category				
1) D - System Demand				
Revenue $	I	$ 332,442	K = J* F* 12* 1000	$501,029
Charge Per Watt	J = I /B /1000 /12	**0.01058**	L = K / F	**0.01058**
2) D - System Customer				
Revenue $	M = D - Q - I	$1,328,161	O = N* E* 12* 1000	$581,743
Charge Per Fixture	N = M / A	**$2.74**	P = O / E	**$2.74**
3) D - Operations & Maintenance				
Revenue $	Q = R*Aa*12 + S*Ab*12	$375,567	T = U*Ea*12 + V*Eb*12	$589,433
Charge Per Fixture Non-LED	R	**$2.77**	U = R	**$2.77**
LED = 10% of Non-LED	S	**$0.28**	V = S	**$0.28**
4) D - Equipment				
Revenue $			W = H- K- O- T	$ 2,535,477
Total D		**$2,036,170**		**$4,207,682**

Note: A, B, C, D - See Appendix 10, page 25.
E, F, G, H - See Appendix 10, page 26.
I - See Application Attachment AN-1, page 3, lines 41 and 42.
R - See Appendix 10, page 23, line 28.
S - See Appendix 10, page 23, line 30.

Street Lighting Operations & Maintenance

Charge Per Fixture

		Source
Test Year Street Lighting O & M	$965,000	A = Appendix 10, page 24, line 26
Non-LED Fixtures		
Rate EOL	8,050	B = Appendix 10, page 25, lines 38 & 41
Rate OL	17,720	C = Appendix 10, page 26, line 66
Total Non-LED	25,770	D = B + C
LED Fixtures		
Rate EOL	32,406	E = Appendix 10, page 25, line 38
Rate OL	-	F = Appendix 10, page 26, lines 36-41
Total LED	32,406	G = E + F
Average Cost Per Fixture	$2.77	H = A / (D+G*10%) / 12
Non-LED Monthly Charge Per Fixture	**$2.77**	I = H
LED Monthly Charge Per Fixture	**$0.28**	J = H * 10%

Street Lighting Operations & Maintenance Expense

	Distribution Expense *		
	Operation	Maintenance	Total
Supervision and Engineering	444	2	446
Street Lighting	519	52	571
Other	67	277	345
Total Distribution Expense	1,031	331	1,362

	Street Lighting Expense		
	Operation	Maintenance	Total
Derived Supervision and Engineering	393	0	393
Street Lighting	519	52	571
Total Distribution Expense	912	53	965

Note * See Application Attachment AN-1, page 10

Street Lighting EOL- Efficient Outdoor Lighting

Unbundled Rate Calculation

		TY Fixtures			Connected	kWh per Fixture		Annual kWh			Current Distribution		Distribution Increase		Distribution Bundled			Proposed Distribution Unbundled (A)					
		All	Mid-		Demand	All	Mid-	All	Mid-				Perm	Step+Recoup				Customer	Demand	O&M	Monthly	Annual	
Watts	Lumens	Night	night	Total	KW	Night	night	Night	night	Total	Rate	Revenue	-34.0%	0.1%	Rate	Revenue	% Chg	2.74	0.01058	$2.77	Rate	Revenue	% Chg
High Pressure Sodium																							
58	4,000	3,753	15	3,768	219	252	117	945,756	1,755	947,511	$8.42	$ 380,719	-$2.86	$0.01	$5.56	$ 251,541	-33.9%	$2.74	$ 0.61	$2.77	$6.12	$ 276,779	-27%
87	5,800	218		218	19	376		81,968		81,968	8.42	22,027	-$2.86	$0.01	5.56	14,553	-33.9%	2.74	0.92	2.77	$6.43	$ 16,816	-24%
127	9,500	356		356	45	550		195,800		195,800	10.36	44,258	-$3.53	$0.01	6.84	29,241	-33.9%	2.74	1.34	2.77	$6.85	$ 29,268	-34%
189	16,000	554	-	554	105	821	379	454,834	-	454,834	11.39	75,721	-$3.88	$0.01	7.53	50,029	-33.9%	2.74	2.00	2.77	$7.51	$ 49,905	-34%
305	30,000	1,731	1	1,732	528	1326	614	2,295,306	614	2,295,920	11.39	236,730	-$3.88	$0.01	7.53	156,408	-33.9%	2.74	3.23	2.77	$8.73	$ 181,523	-23%
466	50,000	132		132	62	2026		267,432		267,432	11.76	18,628	-$4.00	$0.01	7.77	12,307	-33.9%	2.74	4.93	2.77	$10.44	$ 16,532	-11%
1097	130,000	57		57	63	4765		271,605		271,605	22.32	15,267	-$7.59	$0.02	14.75	10,087	-33.9%	2.74	11.60	2.77	$17.11	$ 11,704	-23%
Metal Halide																							
89	5,000	832		832	74	386		321,152		321,152	$8.75	$ 87,360	-$2.98	$0.01	5.78	$ 57,719	-33.9%	2.74	0.94	2.77	$6.45	$ 64,388	-26%
121	8,000	96		96	12	527		50,592		50,592	11.57	13,329	-$3.94	$0.01	7.64	8,806	-33.9%	2.74	1.28	2.77	$6.79	$ 7,819	-41%
190	13,000	-		-	-	825		-		-	12.35	-	-$4.20	$0.01	8.16	-		2.74	2.01	2.77	$7.52	$ -	-39%
206	13,500	88		88	18	896		78,848		78,848	13.00	13,728	-$4.42	$0.01	8.59	9,070	-33.9%	2.74	2.18	2.77	$7.69	$ 8,117	-41%
288	20,000	70		70	20	1251		87,570		87,570	13.22	11,105	-$4.50	$0.01	8.73	7,337	-33.9%	2.74	3.05	2.77	$8.55	$ 7,185	-35%
450	36,000	44		44	20	1956		86,064		86,064	13.59	7,176	-$4.62	$0.01	8.98	4,741	-33.9%	2.74	4.76	2.77	$10.27	$ 5,421	-24%
1080	100,000	103		103	111	4692		483,276		483,276	24.21	29,924	-$8.24	$0.02	16.00	19,771	-33.9%	2.74	11.42	2.77	$16.93	$ 20,927	-30%
Light Emitting Diodes (LED)																							
	Various	32,367	39	32,406						-	$3.37	$ 1,310,499	-$1.15	$0.00	2.23	$ 865,847	-33.9%	2.74		0.28	$3.01	$ 1,171,676	-11%
	Demand	1,321,662	2,845	1,324,507	1,325	4345	2005	5,742,621	5,704	5,748,326	$0.0513	815,367	-$0.01746	$0.00005	0.0339	538,713	-33.9%					$ 168,111	-79%
Total EOL		**40,401**	**55**	**40,456**	**2,619**			**11,362,824**	**8,073**	**11,370,898**		**$ 3,081,834**				**$ 2,036,170**						**$ 2,036,170**	-34%

Note: A - Distribution Component Source:
Customer - See Appendix 10, page 22, line 39
Demand - See Appendix 10, page 22, line 34
O&M - See Appendix 10, page 22, line 44 & 45

Street Lighting Rate OL - Outdoor Lighting

Unbundled Rate Calculation

Connected Watts	Lumens	TY Average Fixtures All Night	TY Average Fixtures Mid Night	TY Average Fixtures Total	Annual kWh per Fixture All Night	Annual kWh per Fixture Mid Night	Connected Demand KW	Annual kWh All Night	Annual kWh Midnight	Annual kWh Total	Current Dist Only Monthly Rate	Current Dist Only Annual Revenue	Distribution Increase Perm -6.82%	Distribution Increase Step+Recoup 0.1%	Distribution Bundled Rate	Distribution Bundled Revenue	Distribution Bundled % Chg	Proposed Distribution Unbundled (A) Cust 2.74	Demand 0.01058	O&M $2.77	Equipment	Monthly Rate	Annual Revenue	% Chg
High Pressure Sodium																								
58	4,000	3,566	-	3,566	252	117	207	898,632	-	898,632	$15.83	$ 677,397	-$1.08	$0.02	$14.77	$ 632,137	-6.7%	$2.74	$0.61	$2.77	$8.65	$14.77	$ 632,137	-6.7%
87	5,800	605	-	605	376	174	53	227,480	-	227,480	15.83	114,926	-1.08	0.02	14.77	107,247	-6.7%	2.74	0.92	2.77	8.34	14.77	107,247	-6.7%
127	9,500	889	2	891	550	255	113	488,950	510	489,460	21.05	225,067	-1.44	0.03	19.64	210,029	-6.7%	2.74	1.34	2.77	12.79	19.64	210,029	-6.7%
189	16,000	825	3	828	821	379	156	677,325	1,137	678,462	29.77	295,795	-2.03	0.04	27.78	276,031	-6.7%	2.74	2.00	2.77	20.27	27.78	276,031	-6.7%
305	30,000	1,289	1	1,290	1,326	614	393	1,709,214	614	1,709,828	30.51	472,295	-2.08	0.04	28.47	440,738	-6.7%	2.74	3.23	2.77	19.74	28.47	440,738	-6.7%
466	50,000	1,902	3	1,905	2,026	937	888	3,853,452	2,811	3,856,263	30.85	705,231	-2.10	0.04	28.79	658,111	-6.7%	2.74	4.93	2.77	18.35	28.79	658,111	-6.7%
1,097	130,000	306	1	307	4,765	2,199	337	1,458,090	2,199	1,460,289	49.51	182,395	-3.38	0.07	46.20	170,208	-6.7%	2.74	11.60	2.77	29.09	46.20	170,208	-6.7%
Metal Halide																								
89	5,000	225	-	225	386	178	20	86,850	-	86,850	$16.51	$ 44,577	-$1.13	0.02	$15.41	$ 41,599	-6.7%	$2.74	$0.94	$2.77	$8.96	$15.41	$ 41,599	-6.7%
121	8,000	133	1	134	527	243	16	70,091	243	70,334	22.60	36,341	-1.54	0.03	21.09	33,913	-6.7%	2.74	1.28	2.77	14.30	21.09	33,913	-6.7%
190	13,000	-	-	-	825	382	-	-	-	-	31.01	-	-2.11	0.04	28.94	-	-6.7%	2.74	2.01	2.77	21.42	28.94	-	-6.7%
206	13,500	119	3	122	896	414	25	106,624	1,242	107,866	31.67	46,365	-2.16	0.04	29.55	43,267	-6.7%	2.74	2.18	2.77	21.87	29.55	43,267	-6.7%
288	20,000	305	3	308	1,251	578	89	381,555	1,734	383,289	31.67	117,052	-2.16	0.04	29.55	109,231	-6.7%	2.74	3.05	2.77	21.00	29.55	109,231	-6.7%
450	36,000	422	6	428	1,956	902	193	825,432	5,412	830,844	31.96	164,147	-2.18	0.04	29.82	153,179	-6.7%	2.74	4.76	2.77	19.56	29.82	153,179	-6.7%
1,080	100,000	266	2	268	4,692	2,165	289	1,248,072	4,330	1,252,402	47.91	154,079	-3.27	0.06	44.71	143,784	-6.7%	2.74	11.42	2.77	27.78	44.71	143,784	-6.7%
Light-Emitting Diode (LED)																								
28	2,500				122													$2.74	$0.30	$0.28	$6.69	$10.00		
36	4,100				156													2.74	0.38	0.28	6.58	9.97		
51	4,800				222													2.74	0.54	0.28	6.58	10.13		
92	8,500				400													2.74	0.97	0.28	7.18	11.17		
142	13,300				617													2.74	1.50	0.28	7.84	12.35		
220	24,500				956													2.74	2.33	0.28	10.20	15.54		
Incandescent																								
105	600	89		89	456		9	40,584		40,584	$9.12	$ 9,740	-$0.62	0.01	$8.51	$ 9,089	-6.7%	$2.74	$1.11	$2.77	$1.89	$8.51	$ 9,089	-6.7%
105	1,000	237		237	456		25	108,072		108,072	10.18	28,952	-0.69	0.01	9.50	27,017	-6.7%	2.74	1.11	2.77	2.88	9.50	27,017	-6.7%
205	2,500	4		4	890		1	3,560		3,560	13.06	627	-0.89	0.02	12.19	585	-6.7%	2.74	2.17	2.77	4.51	12.19	585	-6.7%
448	6,000	-		-	1,947		-	-		-	22.44	-	-1.53	0.03	20.94	-		2.74	4.74	2.77	10.69	20.94	-	-6.7%
Mercury																								
117	3,500	4,922		4,922	509		576	2,505,298		2,505,298	$13.96	$ 824,533	-$0.95	0.02	$13.03	$ 769,442	-6.7%	$2.74	$1.24	$2.77	$6.28	$13.03	$ 769,442	-6.7%
205	7,000	956		956	890		196	850,840		850,840	16.80	192,730	-1.15	0.02	15.68	179,852	-6.7%	2.74	2.17	2.77	8.00	15.68	179,852	-6.7%
292	11,000	57		57	1,269		17	72,333		72,333	20.77	14,207	-1.42	0.03	19.38	13,257	-6.7%	2.74	3.09	2.77	10.79	19.38	13,257	-6.7%
453	15,000	3		3	1,968		1	5,904		5,904	23.76	855	-1.62	0.03	22.17	798	-6.7%	2.74	4.79	2.77	11.87	22.17	798	-6.7%
453	20,000	424		424	1,968		192	834,432		834,432	25.65	130,507	-1.75	0.03	23.94	121,787	-6.7%	2.74	4.79	2.77	13.64	23.94	121,787	-6.7%
1,082	56,000	136		136	4,701		147	639,336		639,336	40.77	66,537	-2.78	0.06	38.05	62,091	-6.7%	2.74	11.44	2.77	21.09	38.05	62,091	-6.7%
Fluorescent																								
330	20,000	2		2	1,433		1	2,866		2,866	$34.79	$ 835	-2.37	0.05	$32.47	$ 779	-6.7%	$2.74	$3.49	$2.77	$23.47	$32.47	$ 779	-6.7%
HPS in Mercury Luminaires																								
180	12,000	8		8	784		1	6,272		6,272	$21.77	$ 2,090	-1.48	0.03	$20.32	$ 1,950	-6.7%	$2.74	$1.90	$2.77	$12.90	$20.32	$ 1,950	-6.7%
413	34,200	5		5	1,794		2	8,970		8,970	27.87	1,672	-1.90	0.04	26.01	1,560	-6.7%	2.74	4.37	2.77	16.13	26.01	1,560	-6.7%
Total OL		17,695	25	17,720			3,947	17,110,234	20,232	17,130,466		$ 4,508,950				$ 4,207,682	-6.7%						$ 4,207,682	-6.7%

Note A - Distribution Components Source:
Customer - See Appendix 10, page 22, line 39
Demand - See Appendix 10, page 22, line 34
O&M - See Appendix 10, page 22, line 44 & 45
Equipment - Non LED equals Distribution Bundled Rate minus Customer, Demand, and O&M Components
Equipment LED - See Appendix 10, page 27, line 59.

Appeal of Public Service Company of New Hampshire d/b/a Eversource Energy
Appendix to Notice of Appeal

Calculation of Current Installed Cost of LED Street Lighting Equipment

	LED Equipment Calculation					
	28 Watts	36 Watts	51 Watts	92 Watts	142 Watts	220 Watts
LABOR COST						
Hours						
Work Tasks	1.41	1.41	1.41	1.41	1.41	1.41
Setup/Span	0.53	0.53	0.53	0.53	0.53	0.53
Travel	0.36	0.36	0.36	0.36	0.36	0.36
Total	2.30	2.30	2.30	2.30	2.30	2.30
Labor Cost (Unloaded)	$ 105.30	$ 105.30	$ 105.30	$ 105.30	$ 105.30	$ 105.30
Labor Loaders						
Non-Productive	$ 16.03	$ 16.03	$ 16.03	$ 16.03	$ 16.03	$ 16.03
Labor	$ 46.14	$ 46.14	$ 46.14	$ 46.14	$ 46.14	$ 46.14
Direct Engineering	$ 13.44	$ 13.44	$ 13.44	$ 13.44	$ 13.44	$ 13.44
Total	$ 75.61	$ 75.61	$ 75.61	$ 75.61	$ 75.61	$ 75.61
Total Labor Cost	$ 180.91	$ 180.91	$ 180.91	$ 180.91	$ 180.91	$ 180.91
EQUIPMENT COST						
Hours	1.15	1.15	1.15	1.15	1.15	1.15
Rate	$ 32.40	$ 32.40	$ 32.40	$ 32.40	$ 32.40	$ 32.40
Total Equipment Cost	$ 37.31	$ 37.31	$ 37.31	$ 37.31	$ 37.31	$ 37.31
MATERIAL COST						
(From Materials Tab)	$ 288.86	$ 279.65	$ 279.65	$ 328.99	$ 383.69	$ 579.55
Material Loader	13.25%	13.25%	13.25%	13.25%	13.25%	13.25%
Total Material Cost	$ 327.13	$ 316.70	$ 316.70	$ 372.58	$ 434.53	$ 656.33
OTHER LOADERS						
Eng. & Sup.	$ 77.19	$ 77.19	$ 77.19	$ 77.19	$ 77.19	$ 77.19
Small Tool	$ 5.43	$ 5.43	$ 5.43	$ 5.43	$ 5.43	$ 5.43
AS&E	$ 2.73	$ 2.67	$ 2.67	$ 2.95	$ 3.26	$ 4.37
Total Other Cost	$ 85.34	$ 85.29	$ 85.29	$ 85.57	$ 85.88	$ 86.99
Total Installed Cost	$ 630.70	$ 620.22	$ 620.22	$ 676.38	$ 738.64	$ 961.55
Annual Carrying Charge	12.73%	12.73%	12.73%	12.73%	12.73%	12.73%
Per Month Charge	**$ 6.69**	**$ 6.58**	**$ 6.58**	**$ 7.18**	**$ 7.84**	**$ 10.20**

Typical Bills by Rate Schedule

Residential Service - Rate R

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 30.12	$ 30.43	$ 0.30	1.01%
200	46.43	47.04	0.61	1.31%
250	54.59	55.35	0.76	1.39%
300	62.75	63.66	0.91	1.45%
400	79.06	80.27	1.21	1.53%
500	95.37	96.89	1.52	1.59%
600	111.68	113.50	1.82	1.63%
650	119.84	121.81	1.97	1.64%
700	127.99	130.12	2.12	1.66%
750	136.15	138.42	2.27	1.67%
1,000	176.93	179.96	3.03	1.71%
1,500	258.49	263.04	4.55	1.76%
2,000	340.05	346.11	6.06	1.78%
2,500	421.61	429.19	7.58	1.80%
3,000	503.17	512.26	9.09	1.81%
5,000	829.41	844.56	15.15	1.83%
7,500	1237.21	1259.94	22.73	1.84%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 13.81	$ 13.81	$ -
Distribution Charge per kWh	0.04508	0.04811	0.00303
Transmission Charge per kWh	0.03011	0.03011	-
Energy Service Charge	0.07068	0.07068	-
Stranded Cost Recovery Charge	0.00982	0.00982	-
System Benefits Charge	0.00743	0.00743	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

Residential Service - Uncontrolled Water Heating

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 18.20	$ 18.16	$ (0.05)	-0.27%
200	31.54	31.44	(0.10)	-0.31%
300	44.87	44.73	(0.15)	-0.33%
400	58.21	58.01	(0.20)	-0.34%
500	71.54	71.30	(0.25)	-0.34%
600	84.87	84.58	(0.29)	-0.35%
700	98.21	97.87	(0.34)	-0.35%
800	111.54	111.15	(0.39)	-0.35%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 4.87	$ 4.87	$ -
Distribution Charge per kWh	0.02210	0.02161	(0.00049)
Transmission Charge per kWh	0.02331	0.02331	-
Energy Service Charge	0.07068	0.07068	-
Stranded Cost Recovery Charge	0.00982	0.00982	-
System Benefits Charge	0.00743	0.00743	-

Note: Immaterial differences due to rounding.

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020

Typical Bills by Rate Schedule

Residential Service - Controlled Water Heating

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 19.42	$ 18.23	$ (1.19)	-6.13%
200	30.26	30.08	(0.18)	-0.59%
300	41.10	41.93	0.83	2.02%
400	51.94	53.78	1.84	3.54%
500	62.79	65.64	2.85	4.54%
600	73.63	77.49	3.86	5.24%
700	84.47	89.34	4.87	5.77%
800	95.31	101.19	5.88	6.17%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 8.58	$ 6.38	$ (2.20)
Distribution Charge per kWh	0.00131	0.01141	0.01010
Transmission Charge per kWh	0.02331	0.02331	-
Energy Service Charge	0.07068	0.07068	-
Stranded Cost Recovery Charge	0.00568	0.00568	-
System Benefits Charge	0.00743	0.00743	-

Typical Bills by Rate Schedule

Residential Service - Optional Time of Day

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		BILL DIFFERENCE	
TOTAL ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 48.46	$ 48.76	$ 0.30	0.63%
200	64.84	65.45	0.61	0.93%
250	73.03	73.79	0.76	1.04%
300	81.22	82.13	0.91	1.12%
400	97.61	98.82	1.21	1.24%
500	113.99	115.50	1.51	1.33%
750	154.94	157.21	2.27	1.47%
1,000	195.90	198.93	3.03	1.55%
1,500	277.80	282.35	4.54	1.64%
2,000	359.71	365.77	6.06	1.68%
2,500	441.62	449.20	7.57	1.72%
3,000	523.53	532.62	9.09	1.74%
5,000	851.16	866.31	15.15	1.78%
7,500	1,260.70	1,283.43	22.72	1.80%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 32.08	$ 32.08	$ -
<u>Energy Charge On Peak kWh</u>			
Distribution	$ 0.14407	$ 0.14710	$ 0.00303
Transmission	0.03011	0.03011	-
Stranded Cost Recovery Charge	0.00844	0.00844	-
System Benefits Charge	0.00743	0.00743	-
<u>Energy Service Charge</u>	0.07068	0.07068	-
Total per On Peak kWh	0.26073	0.26376	0.00303
<u>Energy Charge Off Peak kWh</u>			
Distribution	$ 0.00210	$ 0.00513	$ 0.00303
Transmission	0.01966	0.01966	-
Stranded Cost Recovery Charge	0.00844	0.00844	-
System Benefits Charge	0.00743	0.00743	-
<u>Energy Service Charge</u>	0.07068	0.07068	-
Total per Off Peak kWh	0.10831	0.11134	0.00303
% Sales On Peak	36%	36%	
% Sales Off Peak	64%	64%	

Note: Immaterial differences due to rounding.

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020
Page 32 of 50

Typical Bills by Rate Schedule

Residential Load Control Service - Radio Controlled

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 20.73	$ 18.81	$ (1.92)	-9.26%
200	31.53	30.62	-0.91	-2.89%
300	42.34	42.44	0.10	0.24%
400	53.14	54.25	1.11	2.09%
500	63.95	66.07	2.12	3.32%
600	74.75	77.88	3.13	4.19%
700	85.56	89.70	4.14	4.84%
800	96.36	101.51	5.15	5.34%
900	107.17	113.33	6.16	5.75%
1,000	117.97	125.14	7.17	6.08%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 9.92	$ 6.99	$ (2.93)
Distribution Charge per kWh	0.00131	0.01141	0.01010
Transmission Charge per kWh	0.02331	0.02331	-
Energy Service Charge	0.07068	0.07068	-
Stranded Cost Recovery Charge	0.00532	0.00532	-
System Benefits Charge	0.00743	0.00743	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

Residential Load Control Service - 8 Hour Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		BILL DIFFERENCE	
TOTAL ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 20.73	$ 18.81	$ (1.92)	-9.26%
200	31.53	30.62	(0.91)	-2.89%
300	42.34	42.44	0.10	0.24%
400	53.14	54.25	1.11	2.09%
500	63.95	66.07	2.12	3.32%
600	74.75	77.88	3.13	4.19%
700	85.56	89.70	4.14	4.84%
800	96.36	101.51	5.15	5.34%
900	107.17	113.33	6.16	5.75%
1,000	117.97	125.14	7.17	6.08%
1,200	139.58	148.77	9.19	6.58%
1,500	172.00	184.22	12.22	7.10%
1,800	204.41	219.66	15.25	7.46%
2,000	226.02	243.29	17.27	7.64%
2,500	280.05	302.37	22.32	7.97%
3,000	334.07	361.44	27.37	8.19%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 9.92	$ 6.99	$ (2.93)
Distribution Charge per kWh	0.00131	0.01141	0.01010
Transmission Charge per kWh	0.02331	0.02331	-
Energy Service Charge	0.07068	0.07068	-
Stranded Cost Recovery Charge	0.00532	0.00532	-
System Benefits Charge	0.00743	0.00743	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

Residential Load Control Service - 8 Hour No Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		BILL DIFFERENCE	
TOTAL ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 19.39	$ 18.20	$ (1.19)	-6.14%
200	30.19	30.01	(0.18)	-0.60%
300	41.00	41.83	0.83	2.02%
400	51.80	53.64	1.84	3.55%
500	62.61	65.46	2.85	4.55%
600	73.41	77.27	3.86	5.26%
700	84.22	89.09	4.87	5.78%
800	95.02	100.90	5.88	6.19%
900	105.83	112.72	6.89	6.51%
1,000	116.63	124.53	7.90	6.77%
1,200	138.24	148.16	9.92	7.18%
1,500	170.66	183.61	12.95	7.59%
1,800	203.07	219.05	15.98	7.87%
2,000	224.68	242.68	18.00	8.01%
2,500	278.71	301.76	23.05	8.27%
3,000	332.73	360.83	28.10	8.45%

	Current Rate	Proposed Rate	Difference
Customer Charge	$8.58	$6.38	(2.20)
Distribution Charge per kWh	$0.00131	$0.01141	0.01010
Transmission Charge per kWh	$0.02331	$0.02331	-
Energy Service Charge	$0.07068	$0.07068	-
Stranded Cost Recovery Charge	$0.00532	$0.00532	-
System Benefits Charge	$0.00743	$0.00743	-

Note: Immaterial differences due to rounding.

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020

Typical Bills by Rate Schedule

Residential Load Control Service - 10/11 Hour Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		BILL DIFFERENCE	
TOTAL ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 23.26	$ 19.83	$ (3.43)	-14.76%
200	36.60	32.66	(3.94)	-10.76%
300	49.94	45.50	(4.44)	-8.90%
400	63.28	58.33	(4.95)	-7.82%
500	76.62	71.17	(5.45)	-7.11%
600	89.95	84.00	(5.95)	-6.62%
700	103.29	96.84	(6.46)	-6.25%
800	116.63	109.67	(6.96)	-5.97%
900	129.97	122.51	(7.47)	-5.74%
1,000	143.31	135.34	(7.97)	-5.56%
1,200	169.99	161.01	(8.98)	-5.28%
1,500	210.01	199.52	(10.49)	-5.00%
1,800	250.02	238.02	(12.00)	-4.80%
2,000	276.70	263.69	(13.01)	-4.70%
2,500	343.40	327.87	(15.53)	-4.52%
3,000	410.09	392.04	(18.05)	-4.40%

	Current Rate	Proposed Rate	Difference
Customer Charge	$9.92	$6.99	(2.93)
Distribution Charge per kWh	$0.02665	$0.02161	(0.00504)
Transmission Charge per kWh	$0.02331	$0.02331	-
Energy Service Charge	$0.07068	$0.07068	-
Stranded Cost Recovery Charge	$0.00532	$0.00532	-
System Benefits Charge	$0.00743	$0.00743	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

Residential Load Control Service - 10/11 Hour No Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		BILL DIFFERENCE	
TOTAL ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 21.92	$ 19.22	$ (2.70)	-12.34%
200	35.26	32.05	(3.21)	-9.10%
300	48.60	44.89	(3.71)	-7.64%
400	61.94	57.72	(4.22)	-6.81%
500	75.28	70.56	(4.72)	-6.27%
600	88.61	83.39	(5.22)	-5.90%
700	101.95	96.23	(5.73)	-5.62%
800	115.29	109.06	(6.23)	-5.41%
900	128.63	121.90	(6.74)	-5.24%
1,000	141.97	134.73	(7.24)	-5.10%
1,200	168.65	160.40	(8.25)	-4.89%
1,500	208.67	198.91	(9.76)	-4.68%
1,800	248.68	237.41	(11.27)	-4.53%
2,000	275.36	263.08	(12.28)	-4.46%
2,500	342.06	327.26	(14.80)	-4.33%
3,000	408.75	391.43	(17.32)	-4.24%

	Current Rate	Proposed Rate	Difference
Customer Charge	$8.58	$6.38	(2.20)
Distribution Charge per kWh	$0.02665	$0.02161	(0.00504)
Transmission Charge per kWh	$0.02331	$0.02331	-
Energy Service Charge	$0.07068	$0.07068	-
Stranded Cost Recovery Charge	$0.00532	$0.00532	-
System Benefits Charge	$0.00743	$0.00743	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

General Service 1 Phase

(A)	(B)	(C)	(D)	(E) = (D) - (C)	(F) = (E) / (C)
USAGE		TOTAL MONTHLY BILL		BILL DIFFERENCE	
MONTHLY DEMAND (KW)	MONTHLY USE (KWH)	CURRENT	PROPOSED	AMOUNT	PERCENT
3	375	$ 87.29	$ 69.29	$ (18.00)	-20.62%
3	1,000	168.40	146.32	(22.08)	-13.11%
6	750	157.64	135.60	(22.04)	-13.98%
6	1,500	243.76	224.61	(19.16)	-7.86%
12	1,500	351.46	338.31	(13.16)	-3.74%
30	6,000	1,114.44	1,166.22	51.78	4.65%
40	10,000	1,684.94	1,788.44	103.50	6.14%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 16.21	$ 16.21	$ -
Demand Charge >5kWh			
Distribution	$ 9.49	$ 10.49	$ 1.00
Transmission	7.77	7.77	-
Stranded Cost Recovery Charge	0.69	0.69	-
Total	$ 17.95	$ 18.95	$ 1.00
Energy Charge < 500kWh			
Distribution	$ 0.07604	$ 0.02805	$ (0.04799)
Transmission	0.02807	0.02807	-
Stranded Cost Recovery Charge	0.00732	0.00732	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.07068	0.07068	-
Total	$ 0.18954	$ 0.14155	$ (0.04799)
Energy Charge 501 - 1500 kWh			
Distribution	$ 0.01884	$ 0.02268	$ 0.00384
Transmission	0.01056	0.01056	-
Stranded Cost Recovery Charge	0.00732	0.00732	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.07068	0.07068	-
Total	$ 0.11483	$ 0.11867	$ 0.00384
Energy Charge >1500 kWh			
Distribution	$ 0.00666	$ 0.01709	$ 0.01043
Transmission	0.00566	0.00566	-
Stranded Cost Recovery Charge	0.00732	0.00732	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.07068	0.07068	-
Total	$ 0.09775	$ 0.10818	$ 0.01043

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

General Service 3 Phase

(A)	(B)	(C)	(D)	(E) = (D) - (C)	(F) = (E) / (C)
USAGE		TOTAL MONTHLY BILL		BILL DIFFERENCE	
MONTHLY DEMAND (KW)	MONTHLY USE (KWH)	CURRENT	PROPOSED	AMOUNT	PERCENT
3	375	$ 103.47	$ 85.47	$ (18.00)	-17.39%
3	1,000	184.58	162.50	(22.08)	-11.96%
6	750	173.82	151.78	(22.04)	-12.68%
6	1,500	259.94	240.79	(19.16)	-7.37%
12	1,500	367.64	354.49	(13.16)	-3.58%
30	6,000	1,130.62	1,182.40	51.78	4.58%
40	10,000	1,701.12	1,804.62	103.50	6.08%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 32.39	$ 32.39	$ -
Demand Charge >5kWh			
Distribution	$ 9.49	$ 10.49	1.00
Transmission	7.77	7.77	-
Stranded Cost Recovery Charge	0.69	0.69	-
Total	$ 17.95	$ 18.95	$ 1.00
Energy Charge < 500kWh			
Distribution	$ 0.07604	$ 0.02805	$ (0.04799)
Transmission	0.02807	0.02807	-
Stranded Cost Recovery Charge	0.00732	0.00732	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.07068	0.07068	-
Total	$ 0.18954	$ 0.14155	$ (0.04799)
Energy Charge 501 - 1500 kWh			
Distribution	$ 0.01884	$ 0.02268	$ 0.00384
Transmission	0.01056	0.01056	-
Stranded Cost Recovery Charge	0.00732	0.00732	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.07068	0.07068	-
Total	$ 0.11483	$ 0.11867	$ 0.00384
Energy Charge >1500 kWh			
Distribution	$ 0.00666	$ 0.01709	$ 0.01043
Transmission	0.00566	0.00566	-
Stranded Cost Recovery Charge	0.00732	0.00732	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.07068	0.07068	-
Total	$ 0.09775	$ 0.10818	$ 0.01043

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

General Service - Uncontrolled Water Heating

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 18.15	$ 18.10	$ (0.05)	-0.27%
200	31.42	31.32	(0.10)	-0.31%
300	44.70	44.55	(0.15)	-0.33%
400	57.97	57.78	(0.20)	-0.34%
500	71.25	71.01	(0.25)	-0.34%
600	84.53	84.23	(0.29)	-0.35%
700	97.80	97.46	(0.34)	-0.35%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 4.87	$ 4.87	$ -
Distribution Charge per kWh	0.02210	0.02161	(0.00049)
Transmission Charge per kWh	0.02331	0.02331	-
Energy Service Charge	0.07068	0.07068	-
Stranded Cost Recovery Charge	0.00924	0.00924	-
System Benefits Charge	0.00743	0.00743	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

General Service - Controlled Water Heating

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 19.39	$ 18.20	$ (1.19)	-6.14%
200	30.19	30.01	(0.18)	-0.60%
300	41.00	41.83	0.83	2.02%
400	51.80	53.64	1.84	3.55%
500	62.61	65.46	2.85	4.55%
600	73.41	77.27	3.86	5.26%
700	84.22	89.09	4.87	5.78%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 8.58	$ 6.38	$ (2.20)
Distribution Charge per kWh	0.00131	0.01141	0.01010
Transmission Charge per kWh	0.02331	0.02331	-
Energy Service Charge	0.07068	0.07068	-
Stranded Cost Recovery Charge	0.00532	0.00532	-
System Benefits Charge	0.00743	0.00743	-

Note: Immaterial differences due to rounding.

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020
Page 41 of 50

Typical Bills by Rate Schedule

General Service Load Control Service - Radio Controlled

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 20.73	$ 18.81	$ (1.92)	-9.26%
200	31.53	30.62	(0.91)	-2.89%
300	42.34	42.44	0.10	0.24%
400	53.14	54.25	1.11	2.09%
500	63.95	66.07	2.12	3.32%
600	74.75	77.88	3.13	4.19%
700	85.56	89.70	4.14	4.84%
800	96.36	101.51	5.15	5.34%
900	107.17	113.33	6.16	5.75%
1,000	117.97	125.14	7.17	6.08%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 9.92	$ 6.99	$ (2.93)
Distribution Charge per kWh	0.00131	0.01141	0.01010
Transmission Charge per kWh	0.02331	0.02331	-
Energy Service Charge	0.07068	0.07068	-
Stranded Cost Recovery Charge	0.00532	0.00532	-
System Benefits Charge	0.00743	0.00743	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

General Service Load Control Service - 8 Hour Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 20.73	$ 18.81	$ (1.92)	-9.26%
200	31.53	30.62	(0.91)	-2.89%
300	42.34	42.44	0.10	0.24%
400	53.14	54.25	1.11	2.09%
500	63.95	66.07	2.12	3.32%
600	74.75	77.88	3.13	4.19%
700	85.56	89.70	4.14	4.84%
800	96.36	101.51	5.15	5.34%
900	107.17	113.33	6.16	5.75%
1,000	117.97	125.14	7.17	6.08%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 9.92	$ 6.99	$ (2.93)
Distribution Charge per kWh	0.00131	0.01141	0.01010
Transmission Charge per kWh	0.02331	0.02331	-
Energy Service Charge	0.07068	0.07068	-
Stranded Cost Recovery Charge	0.00532	0.00532	-
System Benefits Charge	0.00743	0.00743	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

General Service Load Control Service - 8 Hour No Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 19.39	$ 18.20	$ (1.19)	-6.14%
200	30.19	30.01	(0.18)	-0.60%
300	41.00	41.83	0.83	2.02%
400	51.80	53.64	1.84	3.55%
500	62.61	65.46	2.85	4.55%
600	73.41	77.27	3.86	5.26%
700	84.22	89.09	4.87	5.78%
800	95.02	100.90	5.88	6.19%
900	105.83	112.72	6.89	6.51%
1,000	116.63	124.53	7.90	6.77%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 8.58	$ 6.38	$ (2.20)
Distribution Charge per kWh	0.00131	0.01141	0.01010
Transmission Charge per kWh	0.02331	0.02331	-
Energy Service Charge	0.07068	0.07068	-
Stranded Cost Recovery Charge	0.00532	0.00532	-
System Benefits Charge	0.00743	0.00743	-

Note: Immaterial differences due to rounding.

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020
Page 44 of 50

Typical Bills by Rate Schedule

General Service Load Control Service - 10/11 Hour Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 23.26	$ 19.83	$ (3.43)	-14.76%
200	36.60	32.66	(3.94)	-10.76%
300	49.94	45.50	(4.44)	-8.90%
400	63.28	58.33	(4.95)	-7.82%
500	76.62	71.17	(5.45)	-7.11%
600	89.95	84.00	(5.95)	-6.62%
700	103.29	96.84	(6.46)	-6.25%
800	116.63	109.67	(6.96)	-5.97%
900	129.97	122.51	(7.47)	-5.74%
1,000	143.31	135.34	(7.97)	-5.56%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 9.92	$ 6.99	$ (2.93)
Distribution Charge per kWh	0.02665	0.02161	(0.00504)
Transmission Charge per kWh	0.02331	0.02331	-
Energy Service Charge	0.07068	0.07068	-
Stranded Cost Recovery Charge	0.00532	0.00532	-
System Benefits Charge	0.00743	0.00743	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

General Service Load Control Service - 10/11 Hour No Switch

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 21.92	$ 19.22	$ (2.70)	-12.34%
200	35.26	32.05	(3.21)	-9.10%
300	48.60	44.89	(3.71)	-7.64%
400	61.94	57.72	(4.22)	-6.81%
500	75.28	70.56	(4.72)	-6.27%
600	88.61	83.39	(5.22)	-5.90%
700	101.95	96.23	(5.73)	-5.62%
800	115.29	109.06	(6.23)	-5.41%
900	128.63	121.90	(6.74)	-5.24%
1,000	141.97	134.73	(7.24)	-5.10%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 8.58	$ 6.38	$ (2.20)
Distribution Charge per kWh	0.02665	0.02161	(0.00504)
Transmission Charge per kWh	0.02331	0.02331	-
Energy Service Charge	0.07068	0.07068	-
Stranded Cost Recovery Charge	0.00532	0.00532	-
System Benefits Charge	0.00743	0.00743	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

General Service - Optional Time of Day
Single Phase

(A)	(B)	(C)	(D)	(E)	(F)	(G) = (F) - (E)	(H) = (G) / (E)
				TOTAL MONTHLY BILL		BILL DIFFERENCE	
MONTHLY DEMAND (KW)	MONTHLY USE (kWh)	ON-PEAK USE (kWh)	OFF-PEAK USE (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
12	1,500	600	900	$ 413.66	$ 439.34	$ 25.68	6.21%
12	1,500	900	600	427.16	452.84	25.68	6.01%
12	3,000	1,200	1,800	578.34	604.02	25.68	4.44%
12	3,000	1,800	1,200	605.33	631.01	25.68	4.24%
30	4,500	1,800	2,700	1,053.52	1,117.72	64.20	6.09%
30	4,500	2,700	1,800	1,094.01	1,158.21	64.20	5.87%
30	9,000	3,600	5,400	1,547.55	1,611.75	64.20	4.15%
30	9,000	5,400	3,600	1,628.54	1,692.74	64.20	3.94%
50	7,500	3,000	4,500	1,727.88	1,834.88	107.00	6.19%
50	7,500	4,500	3,000	1,795.36	1,902.36	107.00	5.96%
50	15,000	6,000	9,000	2,551.27	2,658.27	107.00	4.19%
50	15,000	9,000	6,000	2,686.24	2,793.24	107.00	3.98%
75	11,250	4,500	6,750	2,570.82	2,731.32	160.50	6.24%
75	11,250	6,750	4,500	2,672.05	2,832.55	160.50	6.01%
75	22,500	9,000	13,500	3,805.92	3,966.42	160.50	4.22%
75	22,500	13,500	9,000	4,008.37	4,168.87	160.50	4.00%

	Current Rate	Proposed Rate	Difference
Customer Charge - Single Phase	$ 41.98	$ 41.98	$ -
Demand Charges			
Distribution	$ 13.23	$ 13.92	$ 0.69
Transmission	5.12	5.12	-
Stranded Cost Recovery	0.35	0.35	-
Total Demand Charge	17.25	19.39	0.69
Energy Charge On Peak kWh			
Distribution	$ 0.05335	$ 0.05335	$ -
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00532	0.00532	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.07068	0.07068	-
Total per On Peak kWh	0.13678	0.13678	-
Energy Charge Off Peak kWh			
Distribution	$ 0.00836	$ 0.00836	$ -
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00532	0.00532	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.07068	0.07068	-
Total per Off Peak kWh	0.09179	0.09179	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

General Service - Optional Time of Day
Three Phase

(A)	(B)	(C)	(D)	(E)	(F)	(G) = (F) - (E)	(H) = (G) / (E)
				TOTAL MONTHLY BILL		BILL DIFFERENCE	
MONTHLY DEMAND (KW)	MONTHLY USE (kWh)	ON-PEAK USE (kWh)	OFF-PEAK USE (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
12	1,500	600	900	$ 449.08	$ 457.36	$ 8.28	1.84%
12	1,500	900	600	462.58	470.86	8.28	1.79%
12	3,000	1,200	1,800	613.76	622.04	8.28	1.35%
12	3,000	1,800	1,200	640.75	649.03	8.28	1.29%
30	4,500	1,800	2,700	1,115.04	1,135.74	20.70	1.86%
30	4,500	2,700	1,800	1,155.53	1,176.23	20.70	1.79%
30	9,000	3,600	5,400	1,609.07	1,629.77	20.70	1.29%
30	9,000	5,400	3,600	1,690.06	1,710.76	20.70	1.22%
50	7,500	3,000	4,500	1,818.40	1,852.90	34.50	1.90%
50	7,500	4,500	3,000	1,885.88	1,920.38	34.50	1.83%
50	15,000	6,000	9,000	2,641.79	2,676.29	34.50	1.31%
50	15,000	9,000	6,000	2,776.76	2,811.26	34.50	1.24%
75	11,250	4,500	6,750	2,697.59	2,749.34	51.75	1.92%
75	11,250	6,750	4,500	2,798.82	2,850.57	51.75	1.85%
75	22,500	9,000	13,500	3,932.69	3,984.44	51.75	1.32%
75	22,500	13,500	9,000	4,135.14	4,186.89	51.75	1.25%

	Current Rate	Proposed Rate	Difference
Customer Charge - Three Phase	$ 60.00	$ 60.00	$ -
Demand Charges			
Distribution	$ 13.23	$ 13.92	$ 0.69
Transmission	5.12	5.12	-
Stranded Cost Recovery	0.35	0.35	-
Total Demand Charge	18.70	19.39	0.69
Energy Charge On Peak kWh			
Distribution	$ 0.05335	$ 0.05335	$ -
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00532	0.00532	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.07068	0.07068	-
Total per On Peak kWh	0.13678	0.13678	-
Energy Charge Off Peak kWh			
Distribution	$ 0.00836	$ 0.00836	$ -
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00532	0.00532	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.07068	0.07068	-
Total per Off Peak kWh	0.09179	0.09179	-

Note: Immaterial differences due to rounding.

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Appendix 10 (Settlement)
October 9, 2020
Page 48 of 50

Typical Bills by Rate Schedule

General Service - Space Heating

(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
USAGE	TOTAL MONTHLY BILL		TOTAL BILL DIFFERENCE	
ENERGY (kWh)	CURRENT	PROPOSED	AMOUNT	PERCENT
100	$ 18.75	$ 18.93	$ 0.18	0.95%
200	34.25	34.61	0.36	1.05%
300	49.76	50.30	0.54	1.08%
400	65.26	65.98	0.72	1.10%
500	80.77	81.67	0.90	1.11%
600	96.28	97.35	1.07	1.12%
700	111.78	113.04	1.25	1.12%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 3.24	$ 3.24	$ -
Distribution Charge per kWh	0.03729	0.03908	0.00179
Transmission Charge per kWh	0.02807	0.02807	-
Energy Service Charge	0.07068	0.07068	-
Stranded Cost Recovery Charge	0.01159	0.01159	-
System Benefits Charge	0.00743	0.00743	-

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

Rate GV

(A)	(B)	(C)	(D)	(E) = (D) - (C)	(F) = (E) / (C)
USAGE		TOTAL MONTHLY BILL		BILL DIFFERENCE	
MONTHLY DEMAND (KW)	MONTHLY USE (KWH)	CURRENT	PROPOSED	AMOUNT	PERCENT
75	15,000	$ 2,705.86	$ 2,736.16	$ 30.30	1.12%
75	30,000	3,916.51	3,946.36	29.85	0.76%
150	30,000	5,187.51	5,248.11	60.60	1.17%
150	60,000	7,608.81	7,668.51	59.70	0.78%
300	60,000	10,137.81	10,259.01	121.20	1.20%
300	120,000	14,980.41	15,099.81	119.40	0.80%
500	100,000	16,738.21	16,940.21	202.00	1.21%
500	200,000	24,809.21	25,008.21	199.00	0.80%
1,000	200,000	33,239.21	33,643.21	404.00	1.22%
1,000	400,000	49,169.21	49,631.21	462.00	0.94%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 211.21	$ 211.21	$ -
Demand 1-100 kW			
Distribution	$ 6.07	$ 6.48	$ 0.41
Transmission	10.40	10.40	-
Stranded Cost Recovery Charge	0.65	0.65	-
Total	$ 17.12	$ 17.53	$ 0.41
Demand > 100 kW			
Distribution	$ 5.81	$ 6.22	$ 0.41
Transmission	10.40	10.40	-
Stranded Cost Recovery Charge	0.65	0.65	-
Total	$ 16.86	$ 17.27	$ 0.41
Energy Charge 1 - 200,000 kWh			
Distribution	$ 0.00660	$ 0.00657	$ (0.00003)
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00643	0.00643	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.06025	0.06025	-
Total	$ 0.08071	$ 0.08068	$ (0.00003)
Energy Charge >200,000 kWh			
Distribution	$ 0.00554	$ 0.00583	$ 0.00029
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00643	0.00643	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.06025	0.06025	-
Total	$ 0.07965	$ 0.07994	$ 0.00029

Note: Immaterial differences due to rounding.

Typical Bills by Rate Schedule

Rate LG

(A)	(B)	(C)	(D)	(E)	(F)	(G) = (F) - (E)	(H) = (G) / (E)
				TOTAL MONTHLY BILL		BILL DIFFERENCE	
MONTHLY DEMAND (KVA)	MONTHLY USE (KWH)	ON-PEAK USE (KWH)	OFF-PEAK USE (KWH)	CURRENT	PROPOSED	AMOUNT	PERCENT
3,000	300,000	120,000	180,000	$71,471.55	$ 72,494.55	$ 1,023.00	1.43%
3,000	600,000	240,000	360,000	94,582.95	95,608.95	1,026.00	1.08%
3,000	900,000	360,000	540,000	117,694.35	118,723.35	1,029.00	0.87%
3,000	1,200,000	480,000	720,000	140,805.75	141,837.75	1,032.00	0.73%
3,000	1,500,000	600,000	900,000	163,917.15	164,952.15	1,035.00	0.63%
3,000	1,800,000	720,000	1,080,000	187,028.55	188,066.55	1,038.00	0.55%
3,000	2,100,000	840,000	1,260,000	210,139.95	211,180.95	1,041.00	0.50%

	Current Rate	Proposed Rate	Difference
Customer Charge	$ 660.15	$ 660.15	$ -
Demand			
Distribution	$ 5.17	$ 5.51	$ 0.34
Transmission	10.24	10.24	-
Stranded Cost Recovery Charge	0.49	0.49	-
Total	$ 15.90	$ 16.24	$ 0.34
Energy Charge - On-Peak			
Distribution	$ 0.00553	$ 0.00554	$ 0.00001
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00519	0.00519	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.06025	0.06025	-
Total	$ 0.07840	$ 0.07841	$ 0.00001
Energy Charge - Off-Peak			
Distribution	$ 0.00467	$ 0.00468	$ 0.00001
Transmission	-	-	-
Stranded Cost Recovery Charge	0.00378	0.00378	-
System Benefits Charge	0.00743	0.00743	-
Energy Service Charge	0.06025	0.06025	-
Total	$ 0.07613	$ 0.07614	$ 0.00001

Note: Immaterial differences due to rounding.

DE 19-057 – APPENDIX 11

Timeline of Events and Filings Relating to Settlement

- At time Agreement Filed:
  - Step Adjustment 1 Filing Made
  - Work begins on:
    - Advanced Metering Functionality assessment
    - Distribution Condition/Engineering assessment
    - Review of meter retirements
    - Customer survey
    - Outdoor lighting tariff
    - EV rate proposal
    - TOU rate proposal
  - Staff begins work on Business Process Audit

- November 2020, and annually in November:
  - Vegetation Management Plan for following calendar year filed

- March 1 annually:
  - Reliability Report and Vegetation Management Report Filed into new docket for RRA Docket
  - May 1 – Complete RRA filed including all components and supporting testimony and other information

- March 31, 2021:
  - Results of Distribution Condition/Engineering Assessment and Customer Survey filed as supplemental testimony in LCIRP docket

- May 1, 2021 and May 1, 2022:
  - Step Adjustments 2 and 3 filed

- New Start
  - Within 60 days of approval – convene New Start stakeholder group
  - Within 120 days of approval – file stakeholder group report
  - Quarterly – or on schedule set by stakeholder group:
    - New Start Metrics Reported

- Annually:
  - Fee Free Adoption Rate Information Reported

- First Quarter 2021:
    - New outdoor lighting tariff language proposed

- Four Months After Approval of Agreement:
    - EV rate proposal filed

- Six months After Approval of Agreement:
    - TOU rate proposal filed

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DE 19-057

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
D/B/A EVERSOURCE ENERGY

Petition for Permanent and Temporary Rates

Order Approving Settlement and Permanent Rates

O R D E R N O. 26,433

December 15, 2020

APPEARANCES: Matthew J. Fossum, Esq., on behalf of Public Service Company of New Hampshire d/b/a Eversource Energy; the Office of the Consumer Advocate, by D. Maurice Kreis, Esq., on behalf of residential ratepayers; Primmer Piper Eggleston & Cramer PC, by Elijah D. Emerson, Esq., on behalf of Clean Energy New Hampshire; New Hampshire Legal Assistance, by Raymond Burke, Esq., on behalf of The Way Home; Ellen B. Hawes on behalf of Acadia Center; Higgins Cavanagh Cooney, by Melissa M. Horne, Esq., on behalf of Walmart, Inc.; New Hampshire Department of Environmental Services by Chris Skoglund; PretiFlaherty, by John B. Coffman, Esq., on behalf of AARP New Hampshire; Keyes & Fox LLP, by Melissa E. Birchard, Esq., on behalf of ChargePoint, Inc.; and Suzanne G. Amidon, Esq., Brian D. Buckley, Esq., and Scott J. Mueller, Esq., on behalf of Commission Staff.

This order approves a permanent distribution rate increase for Eversource Energy of $44.987 million effective for service rendered on or after January 1, 2021, to be reconciled back to July 1, 2019, the effective date of temporary rates approved in Order No. 26,265. All Eversource customers, including those customers who take energy service from competitive suppliers, pay distribution rates. The change in distribution rates will coincide with other rate changes on January 1, 2021, that factor into a customer’s monthly bill. The increase in distribution rates will cause the total monthly bill of a residential (Rate R) customer using 600 kWh of electricity to increase by $1.82 or 1.63 percent over the temporary rates approved by Commission Order No. 26,265 (June 27, 2019). The total permanent distribution rate change represents a 4.75% bill increase for the average residential (Rate R) customer compared to the distribution rates that were in effect prior to the Company's initial filing.

I. PROCEDURAL HISTORY

Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource or the Company) filed a Notice of Intent to File Rate Schedules on March 22, 2019. On March 25, 2019, the Office of the Consumer Advocate (OCA) filed a letter of participation in this docket pursuant to RSA 363:28. Eversource filed a Petition for Temporary Rates pursuant to RSA 378:27 on April 26, 2019, requesting a temporary increase in distribution revenue of approximately $33 million for effect on July 1, 2019. Eversource stated that the revenue collected under temporary rates would be subject to refund or recoupment based on the Commission's decision on its request for permanent rates. *See* RSA 378:29. Also on April 26, 2019, Eversource filed notice of its intent to file schedules for permanent rates.

On May 8, 2019, the Commission issued Order No. 26,250, which suspended Eversource's proposed temporary rate tariff pending further investigation and scheduled a Prehearing Conference, technical session, and a temporary rate hearing. During the Prehearing Conference held on May 21, 2019, the Commission granted petitions to intervene filed by Clean Energy New Hampshire (CENH) and The Way Home (TWH). During the course of the proceeding, the Commission also granted petitions to intervene filed by Acadia Center, Walmart Inc. (Walmart), New Hampshire Department of Environmental Services (NHDES), AARP New Hampshire (AARP), and ChargePoint, Inc., (ChargePoint).

On June 13, 2019, Eversource filed a Temporary Rates Settlement executed by the OCA, TWH, Commission Staff and the Company. The Temporary Rates Settlement provided for a $28.3 million temporary increase in Eversource's base distribution rates. Eversource estimated that the agreed-upon temporary rates would result in a distribution rate increase of approximately

2.7 percent on monthly bills of residential customers using 600 kWh of electricity, not taking into account other changes that would occur on August 1, 2019. The Temporary Rates Settlement also provided that Eversource would implement the temporary rate increase for service rendered on and after August 1, 2019, to coincide with changes to Eversource's energy service rate and stranded cost recovery charge rate. On June 27, 2019, the Commission approved the Temporary Rates Settlement in Order No. 26,265.

On May 28, 2019, Eversource submitted its permanent rate petition seeking a rate increase of approximately $70 million, including the initial $33 million temporary rate increase. The Company also requested a 10.4 percent return on equity. In support of its permanent rate request, the Company asserted that it had made substantial investments to maintain and upgrade the reliability and resiliency of its distribution system since its last rate case in 2009, including the investment of $800 million in capital additions. With its filing, the Company included a Motion for Confidential Treatment that the Company later amended and refiled on August 5, 2020. On June 7, 2019, the Commission issued Order No. 26,256, suspending the Company's proposed tariff for a permanent rate increase pending further investigation. The Commission approved a procedural schedule by secretarial letter dated June 28, 2019, and discovery ensued.

On November 4, 2019, Eversource filed an updated revenue requirement calculation that included 16 adjustments accepted by the Company based on discovery requests or other updates. The filing reduced the requested rate increase to approximately $69.3 million.

Pursuant to the procedural schedule, Staff and the OCA filed testimony on December 20, 2019. Walmart, NHDES, CENH, AARP, TWH, and ChargePoint also filed testimony. Staff recommended a revenue requirement increase of $24.4 million and a return on equity of 8.25%. Staff also recommended a disallowance of capital costs associated with approximately

$63 million of plant in service that Staff found were not adequately explained or justified by the Company.

Consistent with the procedural schedule, Eversource filed rebuttal testimony on March 3, 2020, refuting various positions taken by the parties. TWH also filed rebuttal testimony.

On February 5, 2020, Staff filed a motion requesting that the Commission remove Eversource's Electric Vehicle (EV) charging infrastructure proposal from Eversource's petition for a permanent rate increase. NHDES and CENH filed objections to the motion, and the OCA filed a statement in support of Staff's motion.

Shortly thereafter, in March 2020, the COVID-19 pandemic began. As a result, the Commission, on its own and at the parties' request, approved extensions to the procedural schedule. On April 24, 2020, the Governor of New Hampshire issued Exhibit D to Executive Order #29, extending the Commission's authority to suspend rate investigations from 12 to 18 months, due to the COVID-19 pandemic.

The Commission issued Order No. 26,361 addressing Staff's motion regarding EV infrastructure on May 28, 2020. In that Order, the Commission allowed the EV infrastructure proposal to remain as an issue in the permanent rates case. The Commission directed, however, that issues related to the design of rates for charging electric vehicles raised by intervenors should be addressed in Docket No. IR 20-004, the Commission's investigation of EV charging rates and rate structure.

Citing the economic impact of the pandemic and the resulting effects on its members, AARP filed a pleading on April 16, 2020, requesting the Commission order Eversource to file supplemental testimony to update its testimony for the impacts of the pandemic. AARP also requested that the Commission stay the effectiveness of the previously approved temporary rates. Eversource filed an objection to AARP's motion.

On June 16, 2020, the Commission issued Order No. 26,363, denying AARP's motion to suspend the temporary rates. Instead, the Commission directed the Company to update its rate of return testimony in light of economic changes caused by the pandemic, and permitted parties who had previously filed rate of return testimony to update their analysis as well. In Order No. 26,363, the Commission also suspended the investigation into the Company's permanent rate schedules for an additional six months as authorized by the Governor's emergency order, resulting in a full 18-month suspension.

In response to Order No. 26,363, the Company as well as Staff and the OCA filed updated or supplemental testimony on capital costs on July 16, 2020. Staff also filed an updated revenue requirement, along with Staff's Final Audit report related to Eversource's permanent rate case filing.

The Commission issued a secretarial letter on July 7, 2020, approving a revised procedural schedule for hearings in this case, and directing that the hearings be held consistent with remote hearing guidelines used by the Commission in response to the constraints compelled by the pandemic. On July 17, 2020, the OCA submitted a motion for rehearing of certain determinations in the July 7 secretarial letter. In Order 26,392, issued on August 10, 2020, the Commission denied the motion.

On October 9, 2020, Staff and the parties filed a Settlement Agreement (Settlement Agreement), signed by all parties and Staff. The Settlement Agreement, including attachments, if approved, would resolve all issues raised in this case. [1] The Commission conducted hearings

[1] On October 9, 2020, Eversource also filed a petition for the first of three step adjustments to distribution rates included in the Settlement Agreement.

on the Settlement on October 26, 27, and 29. At hearing, the Commission granted the Motion for Confidential Treatment filed by Eversource on August 5, 2020.

On November 30, 2020, Eversource filed a letter requesting that the Commission reopen the evidentiary docket to accept the technical statement of Douglas P. Horton, along with supporting information. The stated purpose of the filing is to substantiate that the settled revenue requirement and base rates include $2,449,051 of rate case expenses to be recovered over 5 years at a rate of $489,810 annually, subject to audit, reconciliation, and further approval of the Commission.

The petition and subsequent docket filings, other than any information for which confidential treatment has been requested of or granted by the Commission, are posted on the Commission's website at https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-057.html.

II. INITIAL POSITIONS OF THE PARTIES AND STAFF

A. Eversource

Eversource presented its proposed permanent rate increase in its pre-filed testimony, with related exhibits and schedules, filed on May 28, 2019. The Company used 2018 as its test year in developing its permanent rate revenue requirement, and calculated its total cost of service to be $436,202,680. The Company computed a distribution revenue deficiency of $69,912,696 based on adjusted test year distribution revenues of $366,289,983. The Company based its calculation of the revenue deficiency on the Company's adjusted test year rate base of $1,215,667,897 and assumed a weighted average cost of capital of 7.62 percent.

Eversource requested a permanent rate increase consisting of an initial $33 million temporary rate increase and a $36.8 million permanent rate adjustment. Eversource stated that an increase in base rates was required in order to strengthen and evolve its distribution system to meet the growing expectation of customers for reliability, resiliency, and more service options including distributed clean energy. In addition, Eversource proposed a series of four annual step adjustments to collect the revenue requirement associated with anticipated capital investments and certain infrastructure expense. The estimated amount of the step increases was $15 million in Step 1 (2019); $21 million in Step 2 (2020); $14 million in Step 3 (2021) and $16 million in Step 4 (2022).

Eversource proposed an overall pre-tax weighted cost of capital of 7.62 percent based on a capital structure of 54.85 percent equity at a cost of 10.4 percent; 41.98 percent long-term debt at a cost of 4.37 percent; and 3.17 percent short-term debt at a cost of 2.45 percent. The Company's filing reflected a number of normalizing adjustments to the test year including an increase of approximately $17.9 million in operations and maintenance expense and $14.7 million in other operating expense. Additionally, Eversource requested authority to amortize and recover its $9 million share of one-time costs to complete the 2012 merger between NSTAR and the Company's parent Eversource Energy, formerly Northeast Utilities.

With its request for permanent rates, Eversource also sought approval of the following additional measures: (1) a Grid Transformation and Enablement Program (GTEP) designed to recover the costs of accelerated investments in distribution upgrades and integration of advanced technologies; (2) a Major Storm Cost Recovery mechanism (MSCR) to permit the Company to annually reconcile annual storm costs above or below the level in base rates; (3) a reconciling mechanism for recovery of the costs of certain vegetation management activities that exceeded rate base revenues for that purpose; (4) a Regulatory Reconciliation Adjustment (RRA) mechanism for the recovery of certain variable costs above the amount included in base rates; (5) a Fee Free proposal to allow residential customers to pay their bills by credit card without a transaction fee; (6) a New Start Arrearage Forgiveness program (New Start) that provides payment assistance for certain residential customers with past due utility bills; (7) a Distribution

Rate Adjustment Mechanism (DRAM) which acts as an umbrella reconciling rate to recover costs associated with certain regulatory expenses and the GTEP, MSCR, Fee Free, New Start, and vegetation management programs; and (8) several other changes to the Company's tariff.

Based on discovery responses and other updates, the Company filed a revised revenue requirement calculation in November 2019, reducing the total amount of its requested rate increase to $69,254,451. Eversource also filed rebuttal testimony responding to testimony filed by Staff, the OCA, and several other parties. Eversource disagreed with Staff's challenges to capital projects, and provided supplemental information on the Company's capital budgeting and planning process. Eversource also defended its proposals for numerous reconciling rate mechanisms. In addition, Eversource reiterated its position that a return on equity of 10.4 percent with a 55/45 equity/debt capital structure was reasonable.

B. OCA

The OCA concluded that the Company's revenue deficiency was approximately $23.5 million and recommended a return on equity of 8.2 percent and an overall rate of return of 6.45 percent. The OCA opposed implementation of the proposed step increases because they were not known and measurable and constituted an inappropriate multi-year rate plan. In addition, the OCA opposed continuation of the Lost Revenue Adjustment Mechanism (LRAM) to calculate the System Benefits Charge because it is a one-sided decoupling mechanism. The OCA supported adoption of a symmetric decoupling mechanism in place of the LRAM, including implementation of conservation voltage reduction. The OCA recommended that the cost of replacing all of the Company's traditional meters with Automatic Meter Reading (AMR) meters and technology be disallowed from rate base. The OCA also recommended a number of rate design adjustments including reduction of the customer charge to $11 per month. In its updated testimony, the OCA recommended a return on equity of 8.64 percent.

C. CleanEnergy and ChargePoint

CleanEnergy stated that the GTEP proposal did not contain actual grid-transformational projects and thus should not be afforded a special rate recovery mechanism. CleanEnergy also recommended that any projects for the integration of advanced energy solutions be addressed in Docket IR 15-296.[2] CleanEnergy and ChargePoint supported the Company's proposal to invest $2 million in distribution facilities for electric vehicle charging stations and recommended that the Company develop alternatives to traditional, demand-based electricity rate structures for Direct Current Fast Charging stations.

D. Department of Environmental Services

NHDES recommended that Eversource include a proposal for an EV time-of-use rate for the residential sector. NHDES stated that utility rates can have a significant role in EV adoption and charging behavior. Because this is the Company's first rate case in ten years, NHDES recommended consideration of rates, rate classes, or rate designs that would overcome the disincentive for investment in Direct Current Fast Charging facilities for EVs.

E. The Way Home

TWH supported approval of the Company's New Start and Fee Free programs and recommended certain changes and enhancements to the program rules and guidelines, including those relating to hardship customers and individuals with limited English proficiency. TWH opposed recovery of the New Start program costs through the DRAM and recommended that those costs be exclusively reflected in distribution base rates. Additionally, TWH opposed reimbursement for 100 percent of the arrearage credits provided in the New Start program

[2] Docket IR 15-296 is designated for the investigation of grid modernization for electric distribution utilities.

because such reimbursement should be decreased to reflect revenues that would not have been collected without the program and the Company's reduced operating expense.

F. AARP New Hampshire

AARP opposed the proposed DRAM and continuation of the LRAM to calculate the System Benefits Charge. AARP recommended reducing the allocation of the rate increase to residential customers, freezing the Outdoor Lighting rates and eliminating the optional time-of-day rate (Rate R – OTOD). Additionally, AARP recommended a reduction of the proposed customer charge from $13.89 to $8.69 and supported the proposed tariff change to allow customers to block electronic enrollments from energy suppliers.

G. Walmart

Walmart stated that electricity is a significant cost for retailers and that the Commission should consider the impact of the proposed rate increase and related allocations and rate design on business customers. Walmart supported continuation of the Company's current 9.67 percent authorized return on equity because it is consistent with recent Commission decisions and national trends. Walmart did not take a position on the Company's proposed cost of service model.

H. Staff

Staff initially recommended an adjusted revenue requirement of approximately $24.4 million and rate base reductions of approximately $63 million. Staff recommended a number of adjustments to the Company's operating income, normalizing adjustments, and rate base. Staff's proposed adjustments to operating income included reductions in the proposed rate increase related to vegetation management, incentive compensation, senior executive retirement plans and enterprise IT expense. Staff also opposed the recovery of any merger related costs. In addition, Staff found that the Company did not adequately explain or justify many of its capital investments and failed to comply with its own budgeting and oversight procedures. As a result, Staff recommended a decrease in rate base of $49.5 million and that the Company be required to undergo a business process audit.

Staff opposed the Company's proposal for step increases and creation of the DRAM. Staff also opposed the use of reconciling rate recovery mechanisms for MSCR, GTEP, New Start, and vegetation management. In addition, Staff opposed recovery of costs for accelerated pole replacement and for other measures contained in Eversource's GTEP proposal. Staff noted that the Company's proposed step increases represent an additional $64.8 million in incremental distribution revenues, almost doubling the Company's request for an increase of $69.9 million in permanent distribution rates.

Staff proposed an overall rate of return of 6.24 percent, based on a return on equity of 8.25 percent and a capital structure of 50 percent equity and 50 percent debt. With respect to rate design, Staff recommended that the Company rely on the Marginal Cost of Service study to move toward more cost reflective rates and minimize intra-class subsidies. Staff supported the implementation of the New Start and Fee Free programs with the addition of certain conditions and reporting requirements.

In its updated testimony, Staff proposed an adjusted revenue requirement of approximately $37.8 million with reductions to rate base of approximately $49.5 million. Additionally, in its updated testimony Staff recommended a rate of return of 6.47 percent and a return on equity of 8.70 percent.

III. SETTLEMENT AGREEMENT

The Settlement Agreement, executed and filed on October 9, 2020, was signed and supported by Staff and all parties to the case. The Settlement reflects the unanimous agreement of all parties to resolve all matters pertaining to Eversource's permanent rate request. The full terms of the Settlement Agreement are found at Hearing Exhibit (Exh.) 58, which contains a 38-page settlement and 11 appendices. The Commission conducted evidentiary hearings on the Settlement Agreement on October 26, 27, and 29, 2020.

Section 1 of the Settlement Agreement provides an introduction and procedural history. The signatories to the Settlement Agreement recommended and request that the Commission approve the Settlement Agreement without modification.

Under Section 2 of the Settlement Agreement, Revenue Requirement Increase, Eversource would be allowed a permanent rate increase of $44.987 million effective for service rendered on or after January 1, 2021, to be reconciled back to July 1, 2019, the effective date of the temporary rates as approved in Order No. 26,265 (June 27, 2019). The agreed-upon revenue increase reflects adjustments that are quantified in the aggregate, but not specifically identified, by agreement of the parties. Section 2 states that the Company shall be authorized to establish a regulatory asset in the amount of $5 million to be recovered over 10 years through an amortization of $500,000 per year. Section 2.4 states that the adjustments made to the revenue requirement for purposes of reaching settlement shall not establish precedent for future rate proceedings.

Section 3, Plant in Service, includes a number of prospective measures designed to address issues raised by various parties in the proceeding. In connection with Staff's concerns about the Company's documentation for certain capital projects and their planning, budgeting, and management activities, the Company, Staff, and the OCA are to work together to develop a regulatory review template. The template would guide the development and production of capital project documentation in order to facilitate review of the Company's future requests to recover the costs of capital investments. Under Section 3.2, the Company also agreed to a business process audit to be conducted and overseen by Staff using a third-party consultant as detailed in Appendix 2. Section 3 also addresses concerns about the Company's investments in AMR infrastructure. Eversource has agreed to depreciate its existing AMR infrastructure using whole life depreciation over nine years. The Settlement Agreement also allows for the retention of an independent accountant to verify the accuracy of the meter plant accounting.

In light of the OCA's observations and concerns regarding the Company's investments in AMR infrastructure, including limitations compared to advanced metering that enables advanced rate designs, Section 4 of the Settlement Agreement requires the Company to conduct an assessment of the feasibility of deploying advanced metering functionality (AMF) in New Hampshire, building on the work recently conducted by Eversource Energy in Connecticut and filed with the Connecticut Public Utilities Regulatory Authority. Section 4 details the parties' agreement regarding the components of the assessment including sensitivity analysis and the use of multiple scenarios.

Section 5, Major Storm Cost Reserve, provides that Eversource will include $12 million annually in rates for the major storm reserve. Rather than implement a reconciling mechanism for storm costs, the Company would be permitted to file for a separate, temporary amortization of storm costs for storm events that exceed $25 million per event, which may include a request to recover costs for repair of damage due to such storm events through a surcharge (Storm Cost Adjustment Mechanism).

Section 6, Vegetation Management Program, would permit the Company to include $27.1 million annually in rates for vegetation management. Of this amount, $11.6 million annually is associated with enhanced tree trimming (ETT) and hazard tree removal; $14.0 million annually is associated with scheduled maintenance trimming (SMT); and $1.5 million annually is associated with full-width right-of-way (ROW) clearing. This section of the Settlement Agreement, and Appendix 3, also detail the operation of the annual reconciliation for vegetation management program costs and requires the Company to undertake an assessment of ETT and hazard tree removal activities in an engineering review.

Section 7 addresses certain cost of service adjustments, including the use of whole-life depreciation and the treatment of an accrual for uncollectible expense. This section permits the Company to recover the environmental reserve/MGP[3] liability in the Stranded Cost Recovery Charge (SCRC) rate at equal cents per kWh across customer classes rather than in distribution rates. To address the shift to the SCRC, the Company has removed an annual amortization of $2.3 million over four years as of December 31, 2018, from its proposed revenue requirement in this case and shall include it in the SCRC filing following approval of this Settlement Agreement.

The agreement on cost of capital is addressed in Section 8. This section would allow the Company a pre-tax weighted cost of capital of 6.87 percent based on a cost of equity of 9.3 percent and a capital structure of 54.4 percent equity and 45.6 percent debt. The capital structure and overall cost of debt has been adjusted to reflect the issuance of $150 million in long-term debt in August 2020 at favorable rates, which reduced both Eversource’s cost of debt and its overall cost of capital.

Implementation of an annual regulatory reconciliation adjustment (RRA) mechanism is detailed in Section 9 of the Settlement Agreement. The RRA would permit the Company to request recovery or refund of a limited set of costs, including: a) regulatory commission annual assessments and special assessments for consultants hired or retained by the Commission and OCA; b) vegetation management program variances; c) property tax expenses, as compared to the amount in base rates; d) lost-base distribution revenues associated with net metering; and

[3] “MGP” refers to a decommissioned manufactured gas plant located in Keene.

e) storm cost amortization final reconciliations and annual reconciliations updated for actual cost of long-term debt. Section 9 also details the operation and calculation of the RRA, and certain annual reporting requirements described in Appendix 4.

Section 10 of the Settlement Agreement would allow Eversource to file three step adjustments. Step 1 would include calendar year 2019 plant-in-service and would be implemented concurrent with the increase in base rates in this proceeding. Step 1 would be capped at $11 million and will exclude new business/growth-related projects. Step 2 would reflect an increase for calendar year 2020 plant-in-service and would be effective August 1, 2021. In addition, Step 2 would be capped at $18 million and limited to projects identified in Appendix 5 with some identified exceptions. Step 3 would reflect an increase for calendar year 2021 plant-in-service to be effective August 1, 2022, and would be capped at $9.3 million and exclude new business/growth-related projects. All step adjustments would be subject to Commission Staff audit and reconciliation based on the results of the audit, and would require Commission approval.

Section 11 addresses concerns regarding certain of Eversource's practices and planned capital investments related to system resilience, and the potential acceleration of those investments under what it described as a Grid Transformation Enablement Program. In light of those concerns, the Company has agreed to hire an engineering firm to perform a condition assessment of the Company's distribution infrastructure, including substations, to provide recommendations related to the Company's short and long-term system needs consistent with the requirements of least-cost integrated resource planning. The Company also agreed to conduct a comprehensive survey of Eversource's customers regarding their prioritization of reliability and resiliency versus cost.

Pursuant to the Settlement Agreement, Eversource would implement the New Start program and a modified version of the Fee Free program in New Hampshire. Sections 12 and 13 set forth the agreement on the terms and conditions for operation of these two programs, which are further described in Appendices 6 (Fee Free) and 7 (New Start). Section 14 specifies certain agreements regarding tariffs and rate design. The parties agreed that: a) the Company's updates to fees and charges in its Terms and Conditions should be approved as filed; b) the tariff provision allowing default Energy Service customers to block incoming enrollments from competitive suppliers will be eliminated; c) the Company will propose a symmetrical decoupling mechanism in its next rate case; d) the Company's customer charge will remain at the level implemented pursuant to the Temporary Rates Settlement Agreement until the Company's next rate case; e) the revenue increase shall be allocated in equal proportionality among the classes; f) within six months of the approval of this Settlement Agreement, the Company will propose amendments to its tariff to revise its optional time-of-day rate for residential customers; g) the Company will phase out declining block rates for all rate classes where such rates exist, with half of the differential eliminated in this rate case and the remainder in the next rate case; and h) the Company will make certain changes and enhancements to its tariff relative to outdoor lighting, as further detailed in Appendix 8.

Under Section 15, the Excess Deferred Income Tax (EDIT) credit associated with Protected Property and Unprotected Pension (amortized over 10 years) would be incorporated as a component of base rates, resulting in a reduction of the revenue deficiency of approximately $5.1 million. As noted in Section 16, Electric Vehicles, matters of rate design regarding electric vehicles have been excluded from this rate case and are only included by reference in the Settlement Agreement with respect to one or more future filings by the Company in a separate docket. Within four months following approval of the Settlement Agreement, Eversource is to file a proposal for make-ready investments supporting EV charging infrastructure in New Hampshire and request that the Commission open a new docket to consider the proposal. The Company's filing is to include a proposal for an alternative to demand charges for electric vehicle charging rates unless the Commission determines otherwise in the adjudicative proceeding announced in Docket No. IR 20-004. The Settlement Agreement does not include or contemplate any specific cost recovery relating to any proposed deployment or development of electric vehicle charging infrastructure.

Appendix 9 includes a revised tariff reflecting the provisions of the Settlement Agreement, and Appendix 10 provides detail on the rate allocations and bill impacts. Under the General Provisions of the Settlement Agreement (Section 18) the Settling Parties agree that the Commission's approval of this Settlement Agreement will not constitute continuing approval of, or precedent for, any particular principle or issue, but such acceptance does constitute a determination that the adjustments and provisions stated in their totality are just and reasonable and consistent with the public interest.

On November 30, 2020, Eversource filed a letter requesting the record be reopened for the purpose of accepting a technical statement and supporting information related to rate case expenses Eversource represented are included in the settled revenue requirement. In the November 30 letter, the Company represented the settled revenue requirement includes $2,449,051 of rate case expenses to be recovered over 5 years at a rate of $489,810 annually, subject to audit, reconciliation, and further approval of the Commission after Eversource files for recovery of its full amount of rate case expenses, with supporting documentation, as required by the Commission's rules. The Settlement Agreement itself, as executed by Staff and the Parties, did not include mention of the rate case expense amount or terms.

IV. COMMISSION ANALYSIS

The Commission is authorized to fix rates after a hearing, upon determining that rates, fares, and charges are just and reasonable. RSA 378:7. In circumstances where a utility seeks to increase rates, the utility bears the burden of proving the necessity of the increase pursuant to RSA 378:8. In determining whether rates are just and reasonable, the Commission must balance the customers' interest in paying no higher rates than are required against the investors' interest in obtaining a reasonable return on their investment. *Eastman Sewer Company, Inc.*, 138 N.H. 221, 225 (1994). In this way, the Commission serves as arbiter between the interests of customers and those of regulated utilities. *See* RSA 363:17-a; *see also EnergyNorth Natural Gas, Inc. d/b/a National Grid NH*, Order No. 25,202 at 17 (March 10, 2011).

Informal disposition is encouraged and may be made of any case at any time prior to the entry of a final decision or order. RSA 541-A:31,V(a), :38. New Hampshire Administrative Rule, Puc 203.20(b) requires the Commission to determine, prior to approving a settlement, that the settlement results are just and reasonable and serve the public interest.

The Commission encourages parties to attempt to reach a settlement of issues through negotiation and compromise, as it is an opportunity for creative problem solving, allows the parties to reach a result more in line with their expectations, and is often a more expedient alternative to litigation. *EnergyNorth Natural Gas, Inc. d/b/a National Grid NH*, Order No. 25,202 at 18 (March 10, 2011). Even where all parties join a settlement agreement, as in this case, the Commission cannot approve it without independently determining that the result comports with applicable standards. *Id*. As the Settlement Agreement pertains to a rate case, the underlying standard to be applied is whether the resulting rates are just and reasonable. RSA 378:7. In addition, RSA 378:28 is an applicable standard in setting permanent rates.

The Settlement Agreement calls for an overall revenue increase of $44.987 million plus step increases of no more than $11 million, $18 million, and $9.3 million, effective for allowed projects and programs closed to plant in 2019, 2020, and 2021, respectively. The revenue increase of $44.987 million will result in a 1.64 percent increase in monthly bills over current approved temporary rates or an increase of $1.82 per month for a typical residential customer taking electric supply from Eversource and using 600 kilowatt hours per month. This increase provides for a return on equity of 9.3 percent, and a capital structure of 54.4 percent equity and 45.6 percent debt.

We compare these amounts to the revenue increase sought by Eversource (a revenue increase of $69,254,451 plus cumulative step adjustments of approximately $64.8 million for 2019, 2020, 2021, and 2022), to that originally recommended by Staff ($24,875,910 revenue increase with no step adjustments) and to that originally recommended by the OCA ($23,452,776 with no step adjustments). From that comparison, we understand that the amount of the revenue increase in the Settlement Agreement represents a negotiated amount that the Settling Parties agree will provide the Company the revenues necessary to provide safe and reliable service. We find the compromise by the diverse parties and Staff to be an indication that the Settlement Agreement is reasonable. *See Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities*, Order No. 25,638 at 15-16 (March 17, 2014).

Based on the evidence before us, we find the capital structure, overall rate of return, and return on equity to be reasonable, although we recognize the significant volatility and changes in the markets over the last several months. *See* Exhs. 52 (Eversource Updated ROE Testimony), 53 (OCA Updated ROE Testimony), 54 (Staff Updated ROE Testimony) and Hearing Transcript of October 26, 2020 (Morning) at 6-8, 12-19, and 21-22. We also note that the return on equity we are approving is within the scope of recent equity returns approved by the Commission, which is a reasonable but by no means definitive indication of an appropriate return on equity. *See Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia*, 262 U.S. 679 (1923) and *F.P.C. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), *see, e.g., Liberty Utilities (Granite State Electric) Corp., d/b/a Liberty Utilities,* Order No. 26,376 at 12 (June 30, 2020); *Unitil Energy Systems Inc.*, Order No. 26,007 at 16-17 (April 20, 2017) (approving a return on equity of 9.5 percent); *Liberty Utilities (EnergyNorth Natural Gas) Corp., d/b/a Liberty Utilities*, Order No. 26,122 at 43 (April 27, 2018) (approving a return on equity of 9.3 percent); *Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities,* Order No. 26,005 at 13 (April 12, 2017) (approving a return on equity of 9.4 percent).

On November 30, 2020, the Commission received a letter from Eversource requesting to reopen the record to admit the Company's technical statement and supporting information. We grant the November 30, 2020, request to reopen the record to admit the technical statement and attachments because we find that it enhances our ability to resolve the matter in dispute. Specifically, the filing calls into question whether the revenue requirement set forth in the Settlement Agreement included a portion of the rate case expenses incurred by the Company during this proceeding.

The record before us includes significant testimony made under oath and adopted during the hearing that supports the required findings, with the exception of findings related to rate case expenses. Neither the Settlement Agreement itself, nor the record, indicated that the settled revenue requirement contained $2,449,051 in rate case expenses, or contained a stipulation of the parties as to the accuracy or prudence of such expenses. Eversource's November 30 filing failed to satisfactorily establish an amount of rate case expenses for recovery from rate payers. The filing acknowledged that the Settlement Agreement did not contain a term related to the rate case expenses. It remains unclear whether all parties agreed to the amount or to the terms proposed by the Company. The filing also did not provide for an accounting mechanism or a downward adjustment to base rates after the expenses are recovered. Moreover, the record did not include evidence necessary to support the findings required by the administrative rules governing rate case expenses, and no waiver request was made. We therefore cannot approve the inclusion of that amount of rate case expenses in base rates. Instead, we direct Eversource to remove the rate case expenses from the settled revenue requirement and file a request for recovery of all its rate case expenses in accordance with the Commission's Chapter Puc 1900 Rules. We direct Eversource to file an exhibit showing its calculation of the revised revenue requirement, any consequent changes to the step adjustments provided for in the Settlement Agreement, and will hold the record open for that purpose. We also direct Eversource to file a tariff that is in compliance with this order.

Otherwise, we have reviewed the record and conclude that the Settlement Agreement balances the interests of the customers' desire not to pay rates that are higher than reasonably necessary and the investors' right to earn a reasonable return on their investment. *See Eastman Sewer Company, Inc.*, 138 N.H. 221, 225 (1994). We find that all investments that are the subject of this proceeding have been prudently incurred and are used and useful in the provision of public utility service. *See* RSA 378:28 (prohibiting any return on any plant, equipment, or capital improvement that has not been found to be prudent, used, and useful). Accordingly, we find the resulting rates, adjusted to remove rate case expenses, are just and reasonable as required by RSA 374:2, RSA 378:7, and RSA 378:28, and that the settlement results as conditioned by this order are just and reasonable and serve the public interest. We therefore approve the Settlement Agreement subject to the conditions herein.

One of the terms of the Settlement Agreement is to develop a regulatory review template to be used to review investments that will be put in rate base using step adjustments between rate cases. We commend the parties for their agreement to improve the review process and believe this kind of documentation will assist the Commission in reviewing the prudency of future investments. While we understand the documentation is being developed to assist review of step adjustments, we also believe the same documentation, filed in years between step adjustments and the next test year, will improve prudency reviews in future rate cases. In response to a question from the Commission about whether such documentation could be filed annually, Mr. Horton responded: "Yes. Again, I wasn't -- I don't have any particular negative reaction to that. But that wasn't, I don't think, what we were intending to do, to file it every year." Tr. Day 1, Morning at 44.

Despite the fact that the parties did not intend to file the regulatory review template annually, we find that such an annual filing in years between step adjustments and test years, will assist review in future rate cases of investments to be included in rate base. We understand the template is subject to further revisions, including after the business process review is completed, and we encourage that development. We direct Staff and the Company to recommend an annual filing date for the regulatory review template in conjunction with the third step adjustment filing expected in May 2022, to be used for investments made in calendar year 2022 forward. To be clear, we will continue to determine whether those documented annual investments are prudent, in rate cases, when the investment less depreciation is to be included in rate base.

Based upon the foregoing, it is hereby

ORDERED, that the Settlement Agreement regarding Permanent Distribution Rates among Eversource, Staff, the Office of the Consumer Advocate, Clean Energy New Hampshire, New Hampshire Department of Environmental Services, The Way Home, Acadia Center, Walmart, Inc., AARP New Hampshire and ChargePoint, Inc. and as modified and conditioned above is hereby APPROVED; and it is

FURTHER ORDERED, that Eversource shall remove any rate case expenses from the settled revenue requirement, and file exhibits and a technical statement demonstrating its calculation of the revised revenue requirement, and any resulting adjustment to the step adjustments provided for in the Settlement Agreement; and it is

FURTHER ORDERED, that Eversource is hereby authorized to begin recovery of the increase to its revenue requirement of $44.987 million, less rate case expenses, in rates effective with service rendered on and after January 1, 2021, to be reconciled to temporary rates approved in Order No. 26,265 (June 27, 2019), consistent with the Settlement Agreement; and it is

FURTHER ORDERED, that Eversource shall file for recovery of all rate case expenses, within 30 days, all in conformity with N.H. Admin. R., Chapter Puc 1900; and it is

FURTHER ORDERED, that Eversource file the regulatory review template annually, after consideration of revisions based on the business process audit and the Step 2 and Step 3 adjustments, beginning with investments made in calendar year 2022; and it is

FURTHER ORDERED, that Eversource is authorized to recover step increases as provided in the Settlement Agreement, and as necessary to reflect removal of rate case expenses from the settled revenue requirement, subject to further review and approval by the Commission for effect January 1, 2021, August 1, 2021, and August 1, 2022; and it is

FURTHER ORDERED, that Eversource shall file tariffs conforming to this order within 15 days of the date of this Order pursuant to N.H. Admin. R., Puc 1603.02(b).

By order of the Public Utilities Commission of New Hampshire this fifteenth day of December, 2020.

Dianne Martin Chairwoman	Kathryn M. Bailey Commissioner

Attested by:

Debra A. Howland
Executive Director

Service List - Docket Related

Docket#: 19-057

Printed: 12/15/2020

Email Addresses

ExecutiveDirector@puc.nh.gov
palvarez@wiredgroup.net
suzanne.amidon@puc.nh.gov
robert.bersak@eversource.com
mbirchard@keyesfox.com
aboyd@acadiacenter.org
brianna@cleanenergynh.org
james.brennan@oca.nh.gov
kelly@cleanenergynh.org
brian.buckley@puc.nh.gov
rburke@nhla.org
richard.chagnon@puc.nh.gov
pradip.chattopadhyay@oca.nh.gov
jessica.chiavara@eversource.com
john@johncoffman.net
roger@fsconline.com
kristi.davie@eversource.com
johndefever@yahoo.com
kurt.demmer@puc.nh.gov
allen.desbiens@eversource.com
paul.dexter@puc.nh.gov
troy.dixon@eversource.com
jdonahue@preti.com
pearl.donohoo-vallett@brattle.com
jay.dudley@puc.nh.gov
Stephen.Eckberg@puc.nh.gov
eemerson@primmer.com
matthew.fossum@eversource.com
tom.frantz@puc.nh.gov
mhorne@hcc-law.com
tklaes@blueridgecs.com
donald.kreis@oca.nh.gov
erica.menard@eversource.com
tmlarkinassociates@gmail.com
madeleine@cleanenergynh.org
karen.moran@puc.nh.gov
scott@sjmuellerlaw.com
dmullinax@blueridgecs.com
rnelson@strategen.com

elizabeth.nixon@puc.nh.gov
amanda.noonan@puc.nh.gov
ocalitigation@oca.nh.gov
rebecca.ohler@des.nh.gov
rorie.patterson@puc.nh.gov
melissa.price@eversource.com
agustin.ros@brattle.com
sanem.sergici@brattle.com
Christa.Shute@oca.nh.gov
christopher.skoglund@des.nh.gov
stower@nhla.org
Jacqueline.Trottier@puc.nh.gov
dvenora@keeganwerlin.com
david.wiesner@puc.nh.gov
jrw@psu.edu
craig.wright@des.nh.gov

PUBLIC UTILITIES COMMISSION

DE 19-057

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY

Notice of Intent to File Rate Schedules

Order Following Hearing on 2019 Step Adjustment

O R D E R N O. 26,439

December 23, 2020

APPEARANCES: Matthew J. Fossum, Esq., on behalf of Public Service Company of New Hampshire d/b/a Eversource Energy; Preti-Flaherty, by John B. Coffman, Esq., on behalf of AARP New Hampshire; and Brian D. Buckley, Esq., on behalf of Commission Staff.

In this order, the Commission authorizes Eversource to recover the annual revenue requirement of $10.611 million associated with $124.9 million of plant additions placed in service in calendar year 2019. Recovery will be made through distribution rates on a service-rendered basis beginning January 1, 2021. For a residential customer using 600 kWh per month, the result is a monthly bill increase of $1.97, or 1.74 percent.[1] Eversource recovers distribution rates from all delivery service customers.

I. PROCEDURAL HISTORY

Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource or the Company) filed a Notice of Intent to File Rate Schedules on March 22, 2019, and on April 26, 2019, filed notice of its intent to file schedules for permanent rates.

On May 8, 2019, the Commission issued Order No. 26,250, which suspended Eversource's proposed temporary rate tariff pending further investigation and scheduled a Prehearing Conference, technical session, and a temporary rate hearing. Several parties

[1] When combined with the permanent rate established in Commission Order No. 26,443 (December 16, 2020), the result is a $3.79 monthly increase for residential customers using 600 kWh per month.

intervened in the proceeding. Over the ensuing year and a half, Eversource and numerous parties engaged in discovery, technical sessions, and other discussions culminating in the Settlement Agreement approved by the Commission in Order No. 26,443 (December 16, 2020). The Settlement Agreement established permanent rates based on a 2018 test year. Among its provisions, the Settlement Agreement contains a provision for three annual step increases to account for plant placed in service in calendar years 2019, 2020, and 2021, effective on August 1 of each year, with the exception of the 2019 step. Because the pandemic resulted in a six-month extension of this proceeding, the Settlement Agreement provides that Eversource shall recover the annual revenue associated with the 2019 step increase over the seven-month period beginning January 1, 2021, to align with Eversource's original proposal to have step increases effective on August 1 of each year. In Order No. 26,443, the Commission ordered Eversource to remove rate case expenses from the calculation of rates. *See* Order No. 26,443 at 20-21.

On October 9, 2020, Eversource filed a petition requesting recovery of $10.651 million in revenue requirement associated with $125.2 million of plant additions placed in service in calendar year 2019, the first step increase established by the Settlement Agreement. Eversource filed supporting pre-filed testimony and related attachments associated with this capital investment. The Commission issued a supplemental order of notice on November 12, 2020, scheduling a merits hearing on December 1, 2020, which was held as scheduled.

The initial filing, testimony, exhibits and other docket filings, other than any information for which confidential treatment has been requested of or granted by the Commission, are posted at https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-057.html.

II. POSITIONS OF THE PARTIES AND STAFF

A. Eversource

Eversource testified in support of the step increase, explaining the development of projects completed in 2019, from the initiation of a project to placement of plant into service. Eversource referenced Attachment LGL/DLP-1 to Ex. 59 in support of the request, and explained that the attachment is the Company's first attempt to address concerns expressed by Staff regarding the Company's project management and planning practices. Eversource said it expects this process will be modified based on the outcome of the business process audit agreed to in the Settlement Agreement. Hearing Transcript of December 1, 2020, (Tr. 12/1/20) at 13-15. Eversource also testified that the Company intended to work with Staff to develop templates to present all project documentation in a consistent manner. Tr. 12/1/20 at 16. The Company said it expects that the business process audit and the templates will make it easier for the Commission to review Company investments. Tr. 12/1/20 at 17.

Eversource discussed several projects and project accounts at hearing. First, the Company witnesses testified regarding the West Rye Substation Project. Eversource represented the Company initiated the project in 2016 and explained how the Project evolved, based on revisions that resulted from engineering changes to the scope of the project. Eversource stated that, because it estimated that the costs of the project would increase, the Company supplemented its initial funding request. In late 2017, Eversource issued a request for proposals for certain project services, and selected a vendor. Based on that selection, the cost of the project increased again, and Eversource filed a second supplemental funding request. Eversource filed another two supplemental funding requests, the last of which Eversource processed in 2019. As a result, the 2019 Step includes the amount of that fourth supplemental funding request, despite the fact that the plant was used, useful, and in service in 2018. Tr. 12/1/20 at 18-29. Eversource explained that after plant is placed in service, the Company continues to receive additional invoices related to the project over a period of time, up to five years, during which time those costs are added to capital investment, which explains why additional costs for the West Rye Project appear to be placed into service in 2019. Tr. 12/1/20 at 57-58.

Eversource also discussed a reduction of $276,837 in capital additions associated with the step adjustment. This downward adjustment was due to costs associated with equipment at the South Milford substation, Peaslee substation, and Laconia substation that Eversource initially identified as transmission costs. Later, those transmission costs were improperly transferred to a distribution account. Hearing Exhibit 61 at 96. Staff issued discovery on those costs. Eversource stated that, as a result of Staff discovery requests, the Company determined that those assets were actually transmission-related, and that the Company should have omitted those costs from the calculation of the step adjustment. Consequently, the Company agreed to remove the $276,837 associated with that equipment from its request for recovery. Tr. 12/1/20 at 28-29. That decision resulted in a decrease of approximately $40,000 in the requested revenue requirement.

Eversource also discussed inclusion of $1.7 million in its annual project account related to claims for damage by third parties. Eversource testified that when a third party is responsible for damage, the cost of repairing the damage is treated as plant in service. Tr. 12/1/20 at 31. Eversource explained that once the Company knows that the damage was caused by a third party, and the third party is identified as responsible for payment, the Company will bill the individual or insurance company for the damages. Once Eversource generates the bill for damages, Eversource credits the work order within the annual project in the calendar year that the Company actually bills the third party. The Company explained that an agreement had been reached with Staff whereby Eversource would recover $1.7 million in the step adjustment subject to Staff audit and reconciliation, and review of the Company's process for collecting third party damage claims. Tr. 12/1/20 at 32-33.

The Company testified regarding its approach to capitalization of certain property tax payments. Tr. 12/1/20 at 71. According to the Company, the rules of the Federal Energy Regulatory Commission allow capitalization of property taxes that accrue while construction work is in progress. In response to Staff questions, the Company said that property tax capitalization applies only to open work orders. The Company did not indicate the degree to which it continues to capitalize property taxes when work orders relating to a portion of the project are held open for months or years after a project is substantially complete. Eversource agreed that those costs would be subject to audit and further reconciliation, as may be appropriate. Tr. 12/1/20 at 72.

Eversource concluded by affirming that all revenue to be recovered through the step adjustment relates to capital plant that is used and useful in utility service to the public, and that the resulting rates are just and reasonable. Tr. 12/1/20 at 108 and 109.

B. AARP of NH

AARP did not take a position on the filing.

C. Staff

Staff testified it conducted an extensive and detailed review of the accuracy of the proposed rates as filed, and of the projects for which the Company has requested recovery in this filing. Staff stated that it appreciates the effort the Company puts into planning and managing these projects, but continues to have concerns about project planning, the 24-month project planning horizon, project management, cost control, documentation, and the format in which Eversource presents these projects to the Commission for review. Tr. 12/1/20 at 108-109. Staff expressed optimism that the results of the business process audit, and the related development of templates for presenting future step increases and capital investment, will remedy these concerns.

With the exception of the $276,837 in capital additions that Eversource agreed to withdraw from this filing, and subject to the review and reconciliations set forth above, Staff observed that the recovery of costs proposed for inclusion in the step increase are for used and useful facilities, and that the costs were prudently incurred. Staff concluded that the resulting rates are just and reasonable, and recommended that the Commission approve the filing, with the exception of the agreed-to exclusion.

III. COMMISSION ANALYSIS

In order to approve this step increase, the Commission must determine whether the investments included in the calculation of the step increase are prudent, used, and useful under RSA 378:28. As noted in the record, both Staff and the Company view the projects requested for recovery within the step increase to be used and useful, their costs to be prudently incurred, and the requested rates to be just and reasonable. Although Staff described some remaining uncertainties relating to the accounting treatment of certain property taxes and property damage attributable to third parties, those uncertainties may properly be reviewed by the Commission Audit Staff and be subject to subsequent reconciliation. As a result, while we find that Eversource may recover those costs through distribution rates, we direct that such costs be subject to an audit by the Commission's Audit Division and reconciliation, as appropriate. We direct that Staff provide the Commission with a copy of the Final Audit Report, and will require Eversource to reconcile its revenue requirement consistent with any adjustments recommended by Staff and approved by the Commission. Recovery shall exclude any rate case expenses and $276,837 in capital additions identified by the Company as transmission costs. Otherwise, we find the expenditures to be prudent, that the resulting rates are just and reasonable, and that recovery of rates is in the public interest.

In addition, we direct Staff to inquire further regarding the Company's treatment of damage to plant from a third party, and the treatment of billing to liable third parties for the repair of damage done to Eversource's facilities. We direct Staff to report on the conclusions they reach following this review, including any further recommendations by Staff regarding the treatment and reporting of how Eversource handles claims for property damage by third parties. Based on Staff's recommendations, as approved by the Commission, the recovery of costs relating to third party property damage may be subject to reconciliation, as appropriate.

At hearing, the Commission noted that Eversource included a "private work" project placed in service in 2019, and for which Eversource requests recovery of the associated revenue requirement. Eversource was unable to explain the nature of that private work. Tr. 12/1/20 at 93-94. We direct Staff to review this issue with the Company and report responsive information to the Commission once it is clear what constitutes private work. In the event that Staff concludes that the costs associated with private work should be removed from the calculation of rates, Staff shall make that recommendation to the Commission for its consideration.

We also direct Eversource to provide Staff with responsive information regarding the accounting treatment of the AMR meters installed in 2019, and we require Staff to report to the Commission on that issue as well. Tr. 12/1/20 at 94. Finally, the Commission asked at hearing about the Company earning a return on the investment in small vehicles. Tr. 12/1/20 at 95. We direct Eversource to provide Staff with responsive information on that issue as well, and will require that Staff share that information with the Commission once Staff is satisfied that the information is complete. While we will not establish a strict timetable for reporting this information, we would like this information to be provided and these discussions to take place in the next six weeks.

Based upon the foregoing, it is hereby

ORDERED, that the capital costs associated with capital investment for plant that was placed in service in calendar year 2019, as calculated by Eversource in its Step 1 filing of October 9 and its recovery through distribution rates, with the exception of the $276,837 cost identified above and any rate case expenses, are hereby APPROVED; and it is

FURTHER ORDERED, that Eversource's request to recover the revenue requirement associated with the approved Step 1 capital investment through rates on a service-rendered basis effective January 1, 2021, and to recover the first year of those annualized costs over a seven-month period ending July 31, 2021, is hereby APPROVED; and it is

FURTHER ORDERED, that Eversource shall file tariff pages as required by N.H. Code Admin. R., Part Puc 1603, conforming to this order within 15 days of the date hereof.

By order of the Public Utilities Commission of New Hampshire this twenty-third day of December, 2020.

Dianne Martin
Dianne Martin
Chairwoman

Kathryn M. Bailey
Kathryn M. Bailey
Commissioner

Attested by:

Debra A. Howland
Debra A. Howland
Executive Director

Service List - Docket Related

Docket#: 19-057

Printed: 12/23/2020

Email Addresses

ExecutiveDirector@puc.nh.gov
palvarez@wiredgroup.net
suzanne.amidon@puc.nh.gov
robert.bersak@eversource.com
mbirchard@keyesfox.com
aboyd@acadiacenter.org
brianna@cleanenergynh.org
james.brennan@oca.nh.gov
kelly@cleanenergynh.org
brian.buckley@puc.nh.gov
rburke@nhla.org
richard.chagnon@puc.nh.gov
pradip.chattopadhyay@oca.nh.gov
jessica.chiavara@eversource.com
john@johncoffman.net
roger@fsconline.com
kristi.davie@eversource.com
johndefever@yahoo.com
kurt.demmer@puc.nh.gov
allen.desbiens@eversource.com
paul.dexter@puc.nh.gov
troy.dixon@eversource.com
jdonahue@preti.com
pearl.donohoo-vallett@brattle.com
jay.dudley@puc.nh.gov
Stephen.Eckberg@puc.nh.gov
eemerson@primmer.com
matthew.fossum@eversource.com
tom.frantz@puc.nh.gov
mhorne@hcc-law.com
tklaes@blueridgecs.com
donald.kreis@oca.nh.gov
erica.menard@eversource.com
tmlarkinassociates@gmail.com
madeleine@cleanenergynh.org
karen.moran@puc.nh.gov
scott@sjmuellerlaw.com
dmullinax@blueridgecs.com

rnelson@strategen.com
elizabeth.nixon@puc.nh.gov
amanda.noonan@puc.nh.gov
ocalitigation@oca.nh.gov
rebecca.ohler@des.nh.gov
rorie.patterson@puc.nh.gov
melissa.price@eversource.com
agustin.ros@brattle.com
sanem.sergici@brattle.com
Christa.Shute@oca.nh.gov
christopher.skoglund@des.nh.gov
stower@nhla.org
Jacqueline.Trottier@puc.nh.gov
dvenora@keeganwerlin.com
david.wiesner@puc.nh.gov
jrw@psu.edu
craig.wright@des.nh.gov

STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

July 19, 2021 - 9:02 a.m.
21 South Fruit Street
Suite 10
Concord, NH

[Hearing also conducted via Webex]

RE: **DE 19-057**
EVERSOURCE ENERGY:
Notice of Intent to File Rate Schedules. ***(Hearing regarding the second step adjustment)***

PRESENT: Chairwoman Dianne H. Martin, Presiding
Commissioner Daniel C. Goldner

Doreen Borden, Clerk
Susan Gagne, PUC Hybrid Hearing Host

APPEARANCES: **Reptg. Public Service Company of New Hampshire d/b/a Eversource Energy:**
Matthew J. Fossum, Esq.

Reptg. Residential Ratepayers:
Donald M. Kreis, Esq., Consumer Adv.
Office of Consumer Advocate

Reptg. New Hampshire Dept. of Energy:
Brian D. Buckley, Esq.
(Regulatory Support Division)

Court Reporter: Steven E. Patnaude, LCR No. 52

I N D E X

E X H I B I T S

EXHIBIT NO.	**D E S C R I P T I O N**	**PAGE NO.**
62	Petition for Second Step Adjustment, including the Testimony of Lee Lajoie, David L. Plante, and James J. Devereaux, with attachments, and the Testimony of Erica L. Menard and Jennifer A. Ullram, with attachments	*premarked*
63	New Hampshire Department of Energy Final Audit Report	*premarked*
64	Supplemental Request Forms, consisting of 64 pages	*premarked*
65	**RESERVED FOR RECORD REQUEST** (RE: Planning and Approval Process)	143
66	**RESERVED FOR RECORD REQUEST** (RE: Alternatives on the Submarine Cable Project)	143
67	**RESERVED FOR RECORD REQUEST** (RE: Emergency or unforeseen project approvals)	143
68	**RESERVED FOR RECORD REQUEST** (RE: Whether there are any additional responses by the Company to the Audit Report)	143

P R O C E E D I N G

CHAIRWOMAN MARTIN: Good morning, everyone. We're here this morning in Docket DE 19-057, which is the Eversource petition for the second step adjustment.

Let's take appearances from counsel, starting with Mr. Fossum.

MR. FOSSUM: Good morning, all. Matthew Fossum, here for Public Service Company of New Hampshire, doing business as Eversource Energy.

CHAIRWOMAN MARTIN: Okay. Thank you. And Mr. Kreis.

MR. KREIS: Good morning, everybody. I am Donald Kreis, doing business as the Office of the Consumer Advocate, here on behalf of residential utility customers. And with me today is our legal intern, who will eventually become a lawyer, Kijana Plenderleith.

CHAIRWOMAN MARTIN: Excellent. Thank you. And Mr. Buckley.

MR. BUCKLEY: Good morning, Madam Chair and Commissioner Goldner. My name is Brian D. Buckley. And I am here representing the

Department of Energy's Regulatory Support Division today.

CHAIRWOMAN MARTIN: Thank you. And welcome in your new capacity. It's our first time seeing you.

Okay. I have Exhibits 62 through 64 prefiled and premarked for identification. Is that the full set of exhibits we'll see today?

MR. FOSSUM: Yes. There may be, since this is a continuation of the rate case, it's possible there may be a reference to a prior one. But the only ones that I'm aware of that anybody is going to present today are those three.

CHAIRWOMAN MARTIN: Okay. And, Mr. Buckley or Mr. Kreis, anything else?

MR. KREIS: Nothing from us.

MR. BUCKLEY: Nothing further from us either.

CHAIRWOMAN MARTIN: Okay. I will reiterate, if the Parties could file a comprehensive exhibit list, it is helpful for me to confirm that those are all of the exhibits, as opposed to getting separate emails, and then I'm not entirely sure that that is the full set. So, if you could do that going forward, it would be much appreciated.

Anything other preliminary matters before we hear from the witnesses?

[No verbal response.]

CHAIRWOMAN MARTIN: Okay. Seeing none. Mr. Patnaude, would you swear in the witnesses please.

(Whereupon ***Lee G. Lajoie, David L. Plante, James J. Devereaux, Erica L. Menard, and Jennifer A. Ullram*** were duly sworn by the Court Reporter.)

CHAIRWOMAN MARTIN: Okay. Thank you. Mr. Fossum, go ahead.

MR. FOSSUM: Thank you.

LEE G. LAJOIE, SWORN

DAVID L. PLANTE, SWORN

JAMES J. DEVEREAUX, SWORN

ERICA L. MENARD, SWORN

JENNIFER A. ULLRAM, SWORN

DIRECT EXAMINATION

BY MR. FOSSUM:

Q I'll start with Mr. Lajoie. Could you please state your name, your position, and your responsibilities for the record?

A (Lajoie) My name is Lee Lajoie. I am the Manager of System Resiliency for Eversource New Hampshire. And a large part of my duties involve dealing with the capital budget for Eversource New Hampshire. I also have two other groups reporting to me, Reliability Reporting group and a group that runs our Distribution Automation Program.

Q And have you previously testified before this Commission?

A (Lajoie) Yes, I have.

Q I'll just stay with you for the moment. Mr. Lajoie, did you back on May 3rd file joint testimony and attachments as part of the Company's submission in what has been marked for identification as "Exhibit 62"?

A (Lajoie) Yes, I did.

Q And, for the portion for which you were responsible, was that testimony prepared by you or at your direction?

A (Lajoie) Yes, it was.

Q Do you have any corrections or updates to that

testimony this morning?
A (Lajoie) No, I do not.
Q And do you adopt that testimony as your sworn testimony for this proceeding?
A (Lajoie) Yes, I do.
Q Thank you. Turning to Mr. Plante. Could you please state your name, your position and responsibilities for the record? And it appears you're on mute, Mr. Plante.
A (Plante) Yes. Sorry about that. Yes. Good morning, everyone. My name is David Plante. And I am the Manager of Project Management-New Construction for Eversource in New Hampshire. And, basically, my role is to run the Project Management group here in New Hampshire overseeing the project managers who actually manage the projects that we execute.
Q And have you previously testified before this Commission?
A (Plante) I have.
Q And, Mr. Plante, did you also back on May 3rd file joint testimony and attachments in what has been marked for identification as "Exhibit 62"?

A (Plante) Yes.
Q And, for the portion for which you were responsible, was that testimony prepared by you or at your direction?
A (Plante) Yes.
Q And do you have any corrections or updates to that testimony this morning?
A (Plante) I do not.
Q And do you adopt that testimony as your sworn testimony for this proceeding?
A (Plante) I do.
Q And, lastly, for the preliminaries, Mr. Devereaux, could you please state your name, your position and responsibilities for the record?
A (Devereaux) Yes. Jim Devereaux, Manager of Budgets and Investment Planning. I'm responsible for financial reporting, in-house analysis and oversight of the capital programs and O&M for New Hampshire operations.
Q And, Mr. Devereaux, have you previously testified before this Commission?
A (Devereaux) I have not.
Q In light of that, could you just very briefly

state your experience and qualifications for the record?

A (Devereaux) Sure. I graduated from St. Michael's College and followed up -- with a Business degree, and followed up with a Master's of Business Administration from Bentley University.

I've worked for the Company since 1985, mostly in the gas business in Massachusetts. I held the role of Director of Gas Service and Supply for about ten years, moved on to Investment Planning, and have been in my current position since 2019.

Q And, Mr. Devereaux, did you also back on May 3rd file joint testimony and attachments in what has been marked for identification as "Exhibit 62"?

A (Devereaux) Yes, I did.

Q And was that testimony prepared by you or at your direction?

A (Devereaux) Yes, it was.

Q And do you have any corrections to that information this morning?

A (Devereaux) I do not.

Q And do you adopt that testimony as your sworn

testimony for this proceeding?
A (Devereaux) Yes, I do.
Q All right. Moving on, and turning to Ms. Menard. Could you please state your name, your position and responsibilities for the record?
A (Menard) My name is Erica Menard. I am the Manager of Revenue Requirements for New Hampshire. And, in that capacity, I am responsible for revenue requirement calculations for various rate and regulatory filings before this Commission.
Q And have you previously testified before this Commission?
A (Menard) Yes, I have.
Q And did you back on May 3rd file joint testimony and attachments with Ms. Ullram as part of the Company's submission, and which has been marked identification as "Exhibit 62"?
A (Menard) Yes.
Q And was that testimony prepared by you or at your direction?
A (Menard) Yes, it was.
Q And do you have any corrections or updates to that testimony this morning?

A (Menard) No, I do not.
Q And do you adopt that testimony as your sworn testimony for this proceeding?
A (Menard) Yes, I do.
Q And turning to Ms. Ullram. Could you please state your name, your position and responsibilities for the record?
A (Ullram) Good morning. My name is Jennifer Ullram. I am the Manager of Rates for Connecticut and New Hampshire. In my role, I'm responsible for rates, cost of service, and rate design for both Connecticut and New Hampshire.
Q And have you previously testified before this Commission?
A (Ullram) Yes, I have.
Q And did you also on --

CHAIRWOMAN MARTIN: Mr. Fossum?

MR. FOSSUM: Yes.

CHAIRWOMAN MARTIN: I apologize for interjecting. Mr. Lajoie is no longer on my screen. Can other folks see him?

WITNESS MENARD: He has an error with his computer and it is restarting.

CHAIRWOMAN MARTIN: Okay. Excellent.

Mr. Fossum, I think we can proceed, until you need to have questions of Mr. Lajoie.

MR. FOSSUM: Hopefully, he'll be back in just a moment or three.

BY MR. FOSSUM:

Q Where did we leave off? I believe I asked, but just in case, did you file testimony and attachments, along with Ms. Menard, back on May 3rd, and included in what has been marked for identification as "Exhibit 62"?

A (Ullram) Yes, I did.

Q And was that testimony prepared by you or at your direction?

A (Ullram) Yes, it was.

Q And do you have any corrections or updates to that information?

A (Ullram) No, I do not.

Q And do you adopt that testimony as your sworn testimony for this proceeding?

A (Ullram) Yes.

MR. FOSSUM: Thank you. Now, with the preliminaries out of the way, I suppose, I have just a few questions, but I prefer to wait for Mr. Lajoie to rejoin before I continue. So, I'll --

CHAIRWOMAN MARTIN: Okay. Why don't we take a five-minute recess, until 9:20 or so, to give him the chance to rejoin.

All right. Off the record.

(Recess taken at 9:13 a.m. and the hearing resumed at 9:19 a.m.)

CHAIRWOMAN MARTIN: Okay. Let's go back on the record. Mr. Fossum.

MR. FOSSUM: Thank you. And I appreciate the few moments to make sure that the issues were resolved, and hopefully they won't repeat.

With that said, I just have a -- as I said, I don't have a lot of the questions, but a couple of things.

BY MR. FOSSUM:

Q Referring to the testimony of Messrs. Lajoie, Plante, and Devereaux, and in particular the material included in Attachment LGL/DLP/JJD-1, could you please explain what is included in that attachment and what that shows for the Commission?

A (Devereaux) Yes. That attachment includes specific information on each of the projects that are filed in this, in this proceeding. As described in earlier, it has plant in service, spending for that particular project, it indicates whether a supplement was necessary for that project, and it shows the lifetime costs of the project versus the authorization.

Q And is this information presented in a format that had been discussed with the -- I guess what is now DOE Staff?

A (Devereaux) Yes. This was the same format that was used in the filing of last year. And it's split between specific projects that are new to this filing, carryover projects that have had costs already applied for recovery, and annual projects, that are annual projects, you know, each one is for a year, and the charges roll up into that particular project on an annual basis.

Q Thank you for the general overview. I'd look to Messrs. Plante or Lajoie as may be appropriate, to just -- if you could very briefly please just focus on one or two of the projects, and describe the detail that is provided there for the Commission's review?

A (Lajoie) Okay. I will start. As one example, on Bates Page 025, Line 7, is a description of Project Number A16N01, which is a submarine cable project.

The project was initiated to replace two different submarine cables that went from the mainland out to islands in Lake Winnipesaukee, Welch Island and Lockes Island. In particular, the cable to Welch Island was a mile long cable approximately, crossing one of the deepest spots of Lake Winnipesaukee.

It's a bit of an unusual project for us, in that we don't install a lot of submarine cable. The cables that were physically there had been installed one of them in the '40s and one of them in the 1960s. The replacement of these cables had been on our radar, if you will, for a number of years, and had been kept getting deferred for a number of reasons.

Finally, in 2016, the project was initiated to start the work on replacing these. The initial request, which was approved, was authorized for $360,000. As time went on, and --

Q And, Mr. Lajoie, just I'll interrupt you just for a moment to say is to focus on what is included in the attachment, that 360,000 you mentioned, where does that show?

A (Lajoie) The "360,000" is in Column -- I'm sorry, the font is really small, "360,000" is in Column I, which is the "Pre-Construction Authorization".

So, as we progressed with the project, there were a significant number of permits required. There was Department of Environmental Services' Wetlands Permit, Shorelands Permits, water crossings, and so forth.

Excuse me. As the project progressed, and we went out for bids for the actual installation of the project, it became very clear that the initial authorization, the pre-construction authorization of 360,000, was not going to be enough to cover the replacement of these cables. So, a supplemental request was submitted. This was based on actual bids that have been received. We got the bids the first time around, looked at the numbers, thought they were really high. So, we actually went out for a second round of bids just to be sure -- to be sure that we were getting the best price possible.

And I'm getting a note that this may be Bates 026.

CHAIRWOMAN MARTIN: I believe it's red Bates Page 026.

WITNESS LAJOIE: Okay.

CHAIRWOMAN MARTIN: I think we have multi-colors again for this one, and it's located in a different corner, because of the -- I'm having to turn the page. Can you confirm that? It is the red Bates Page 026, Line 7?

WITNESS LAJOIE: Yes. That's correct.

CHAIRWOMAN MARTIN: Okay. Thank you.

WITNESS LAJOIE: Sorry about that.

CONTINUED BY THE WITNESS:

A (Lajoie) So, anyways, we had gone out for bids twice around, two separate times, gotten bids from a number of contractors. The low-price bidder was the one that was selected for the installation. So, the supplemental request was submitted. And the various columns on this spreadsheet, the "Supplemental Authorization" for "1.917 million", as shown in Column J. The actual project cost of 1.883 -- well, 1.884 with a little bit of rounding, is shown in Column M. So, the project did come in at less than the supplemental authorized amount.

I do want to point out that the supplemental was submitting prior to construction starting. There had been some expenditures at that point for the permitting and so forth. But, before we proceeded with construction, we wanted to make sure we had everything in place so we knew the project could proceed. So, that's where those charges came in. Again, less than that original 360 authorized amount, but they are rolled into the nearly $1.6 million for the installation -- excuse me -- the 1.883 million for the actual final cost.

Q Thank you for walking through that detail.

Mr. Plante, just is there another -- could you provide another example, and we'll keep it brief, of the detail that's provided for review in this attachment?

CHAIRWOMAN MARTIN: Mr. Lajoie, could you please mute in between? Thank you.

BY THE WITNESS:

A (Plante) All right. Certainly. Thank you. And

I'll talk a little bit about the Pemigewasset Transformer Replacement Project at the Pemigewasset Substation, which is shown on Bates 026, Line 19. This project was an upgrade to replace -- to an existing substation, which had an overloaded transformer. So, we're actually, basically, replacing the existing transformer with a newer, larger transformer.

And, based on the outside engineers we had retained solely for purposes of developing project estimates, the initial estimate was made for this project in 2017, which led to the February 2018 full funding authorization of 4.1 million.

Initially, the engineering assumptions for the project indicated that the existing control house would have -- would be large enough to accommodate the new protection and control equipment that was required. However, as the project engineering developed, that turned out not to be the case, as noted in the far right, Column U, we have a little bit of an explanation of the major driver for the cost change. And there was a need to make modifications that led to some additional costs as shown in the Supplement columns.

The matter was further complicated by issues discovered during the testing period that required additional design work and subsequent construction modification. While the contract with the design firm put some of those costs on them, there were other costs that needed to be addressed, and led to the final amount shown in Column K.

While we do work to control costs and anticipate issues, because some of the issues were not discovered until the testing phase, those were costs that we did not anticipate. And, as discussed in previous testimony, our revised authorization process would have progressed the engineering and contracting such that the major assumptions are validated and quantified prior to authorizing full funding. And had this been the case, additional funding may still have been required, however at a much lesser incremental value.

And, you know, this is one of those few remaining projects that we kind of consider is a legacy of our previous authorization process, where we had authorized it for full funding before we really had launched into the engineering. But we don't do it that way any longer.

BY MR. FOSSUM:

Q Thank you both for the detail. And I'll ask, and I'll ask that each one of you, that's Mr. Lajoie -- Mr. Lajoie, Mr. Plante, and then Mr. Devereaux, in that order, that each of you answer the same question.

And is it your position, and the Company's position, that each of the identified projects included in these attachments were prudent and the costs for those projects are reasonable?

A (Lajoie) Yes, it is.

A (Plante) Yes, it is.

A (Devereaux) Yes, it is.

Q Thank you. Turning to Ms. Menard and Ms. Ullram. Did you review the various projects identified in the testimony and attachments of Messrs. Lajoie, Plante, and Devereaux?

A (Menard) Yes.

A (Ullram) Yes.
Q And what did you do with that information relative to this filing?
A (Menard) So, for our section, we took the projects that were identified as going into service, and we worked with the cost of those projects, the plant additions, retirements, you know, all of the relevant information associated with those projects, and calculated the revenue requirement to support those costs. That was consistent with the Settlement Agreement, in Section 10, there was a template that was identified as to how step adjustments would be presented. So, we took that information, calculated the final revenue requirement that will be used to adjust distribution rates.
A (Ullram) And then, what I did was, once Ms. Menard provided the revenue requirements, I applied the revenue allocation methodology that was approved in the Settlement Agreement, to calculate the proposed rates that are shown on, in red, on Bates Pages 052 and 053.
And, you know, I described in my testimony, on Bates Pages 039 and 040, that,

because this first -- because we had last year's step increase was recovered over a seven-month period, as opposed to the twelve-month period, the impact last year for the step increase was higher. So, when calculating the incremental step for this step increase, the Step 2 increase, the revenue requirements to be recovered through rates for the second step adjustment is lower than the revenue requirement actually being requested that's shown in Ms. Menard's testimony.

Q Thank you both. And understanding that, could you please briefly explain the impact on rates as a result of this step? And where is that shown in the filing?

A (Ullram) So, the impact to rates is shown in Exhibit 62, red Bates Page, let me just confirm, starting on Page 74, we provide the impacts to various rate classes. It starts on Page 74, and goes through Page, pardon me, 95 -- 96.

And, for a typical, you know, a 600 kilowatt-hour Rate R residential customer, they will see an overall increase for this step adjustment of 38 cents per month. You know, in our exhibit, on Bates Page 074, we show the impact of the RRA and the distribution rate change together, which was an impact of 27, but just -- 27 cents per month, but, just isolating the step adjustment, it's a 38 cent per month increase.

Q Thank you. Yes, I'm unmuted. And last, for both of you, is it your position and the Company's position that the rates, as calculated and presented in Exhibit 62, are just and reasonable and in the public interest?

A (Ullram) Yes.

A (Menard) Yes.

MR. FOSSUM: Thank you. That's what I had for the direct.

CHAIRWOMAN MARTIN: Okay. Thank you, Mr. Fossum. Mr. Kreis.

MR. KREIS: Thank you, Chairwoman Martin.

I think that the bulk of my questions are going to be for Mr. Lajoie, but he is totally welcome to punt any question over to any of his colleagues if he wants.

And I'm hoping, now that he's a dead ringer for Ernest Hemingway, that maybe he can throw in a few literary allusions as well.

CROSS-EXAMINATION

BY MR. KREIS:

Q Looking at Exhibit 62, which is the Company's filing, and doing my best to stick to the red Bates page numbers in that exhibit, let me start with a general question.

So, the prefiled testimony, in Exhibit 62, the part that's written by Messrs. Lajoie, Plante, and Devereaux, talks about the Company's budget process. And I'm wondering if Mr. Lajoie, or perhaps one of the other witnesses, could help me understand the relationship between the Company's annual budgeting process and the least cost integrated planning process that the Company has to go through in order to meet the requirements of the Least Cost Integrated Resource Planning statute?

A (Lajoie) The annual program capital budgeting process involves proposal of projects to be completed statewide, the justification of those projects on a preliminary basis, prioritizing those projects, and looking at how much capital is available to complete the projects. Each of those projects has to include alternatives, which could include non-wires alternatives; they could include non-traditional utility solutions; or they could be the more traditional poles and wires solutions.

So, in the justification for those projects, those items are considered, which would, you know, kind of lend toward the LCIRP process, completing the requirements of the LCIRP process.

Does that kind of answer the question?

Q Yes. But here's a follow-up. Is there any requirement in that budget authorization process that a particular request tie back to the Company's most recent Least Cost Integrated Resource Plan?

A (Lajoie) I don't believe there is any particular requirement that an individual project tie back to the LCIRP, no.

Q On Bates Page 014, at Line 5 and 6, you testify that "project authorization may be granted throughout the year as circumstances warrant." I'm wondering how that isn't a potential end-run around both the annual budgeting process and the least cost integrated resource planning process, given that it basically says, if I'm reading that correctly, that, really, the Company can authorize any project at any point throughout the year, if circumstances warrant?

A (Lajoie) Well, as just an example of what that refers to, a few months ago, in Berlin, New Hampshire, one of the substation transformers had an internal fault. So, we opened up the transformer, did a whole lot of testing and so forth, and determined that the transformer needed to be replaced. This was nothing that was on our capital budget plan. We assumed that the transformer would continue to function. But, in order to maintain service within the greater North Country, really, because this transformer actually ties to lines that feed over into Colebrook, and down into Lost Nation, and Whitefield/Lancaster. So, it's that greater area. In order to maintain the reliability of service to those customers, we made the decision that we needed to replace that transformer. That work is actually in progress now.

So, authorization for this, Dave

Plante's work is -- group is actually working on putting together the full engineering costs and so forth of what it's going to take to replace that transformer. But that's one that's being approved now for completion this year.

So, it's not really that we're doing an end-run around the LCIRP or any associated requirements, it's the condition changed, in that the transformer failed. And the only reasonable solution to maintaining reliability to the area is to replace the transformer. So, we'll be taking a unit that was actually removed from service somewhere else, because it was too small, relocating it to Berlin, and putting it in service in that substation.

Q Thank you. That example was super helpful, at least in helping me understand how all this works.

So, in that instance, it sounded like, and you can tell me if I heard you or understood you correctly, it sounded like that was, essentially, an unanticipated set of circumstances that required the Company, for reliability reasons, to act in the middle of what -- in the middle of a budget year, essentially. Do I have that right?

A (Lajoie) Yes. That's correct. Yes.

Q So, is there a requirement -- if I were the person in Eversource who is tasked with seeking approval for a project like that, outside of the regular budget process, would there be any requirement for me to demonstrate that the project that I'm seeking approval for is the result of unanticipated circumstances?

A (Lajoie) Yes. That is definitely part of the justification form that is put together for the project, the Project Authorization Form. Before that form even gets submitted, though, we have -- I have participated in a number of meetings, along with Dave Plante's group, and others, to discuss "Hey, what alternatives do with have?" And, you know, "Do we really need to do this?" And the planning people get involved and so forth. So, there's a lot of discussions that happen internally, and then all of that gets rolled into this Project Authorization Form that's going to be submitted shortly, to, again, authorize the investment in replacing that transformer in Berlin.

Q Super. Looking now at Bates Page 016, again, I'm trying to stick to the red Bates numbers, just want to make sure I have the right one. Yes, I do. On that page, there is a discussion that's labeled "Cost Control Procedures". And the question is "Once the construction budget is finalized, does the Company have measures in place to control costs as the projects are designed and completed?"

And the beginning of the answer to that question says "The Company's PAP" -- first of all, can you remind of what "PAP", "PAP", stands for?

A (Lajoie) "Project Authorization Process".

Q Super. Okay. So, what you said was "The Company's Project Authorization Process has been established to allow for incremental project funding authorizations based upon the developmental stage of the project which controls the amount of capital that can be expended on a project until the project is fully defined and most cost components have sufficient detail to secure quality estimates."

This is probably a testament to my poor reading comprehension abilities. But I have trouble understanding that sentence. And I'm wondering if you could maybe explain it in more detail or paraphrase it or render it in more plain English?

Again, I apologize, because it's really probably my fault for not quite getting what you were trying to say.

A (Lajoie) No. Happy to walk through this. The process works -- well, an individual project, and actually this ties back to Dave Plante's testimony a few minutes ago about the Pemigewasset Substation, the way the process works now, and has for the past couple of -- past few years, is a project gets proposed, and it is granted preliminary funding. And that preliminary funding is to start work on the detailed engineering to be able to come up with a firm estimate of what the total project cost will be.

And, actually, Dave, if you wouldn't mind just jumping in here, since you're more closely involved with that whole side of it, if that's okay, please.

A (Plante) Sure. Yes, I'm happy to. You know, Lee doesn't necessarily get as involved with the substation funding processes as I do. He runs the other side of the funding processes for distribution line projects.

And, as far as substation projects go, and this is kind of what we're targeting here, it applies to all of our authorizations, but more specifically for substation projects as well. And the way I'll address it is we now have a multistage funding authorization process that is independent of what the, say, trustee budget is for a project in any given year. It's specific to each of the projects that we're developing. We first seek an initial funding authorization from the Eversource Project Authorization Committee, "EPAC" is the acronym that we use. And that funding, usually a fairly low value, is used to begin developing the concept for the project and the solution.

We'll hire a vendor sometimes to help us develop the project scope, and then we would use that. Sometimes we'll do that internally as well. We will then use that knowledge to develop a higher level estimate to then seek partial funding for the project, which would be another discrete authorization event through the EPAC process. We would develop another Project Authorization Form seeking partial funding to complete the detailed engineering, initiate any procurement events that might be valuable in determining specific materials costs. We may advance any necessary project permitting, site plan approvals through the local municipalities, for instance, through this partial process. And that would get us to the point where we have eliminated, probably not all, but many of the major unknowns for the project, from a cost perspective and from a scope perspective.

We would then develop what we would call a "full funding estimate" and a "Full Funding Authorization Form", which we would then present to the EPAC to receive authorization to complete the project.

So, that's kind of the incremental project funding authorization process that we use now. And that process is, you know, is kind of an evolution of what was our previous process, where we had, in many cases, sought full funding before we really gotten very far along with the engineering.

And, then, lastly, once, you know, if we do get to the point where we are well along in construction, and something transpires, and looks like we need more funds than we have authorized, we would then present a Supplemental Funding Request. And that's kind of the last type of funding that is described through the EPAC process.

Does that help?

Q That helped me. Hopefully, it helped others. Thank you.

CHAIRWOMAN MARTIN: Mr. Kreis?

MR. KREIS: Yes.

CHAIRWOMAN MARTIN: I apologize for interjecting. I think it would be helpful to the Commission if we could have the Company submit as a record request a description of that process, including a flow chart, or something along those lines, to clearly identify the process that was just described.

And, Mr. Fossum, any questions on that?

MR. FOSSUM: No. I believe that we've presented essentially a narrative like that, and I believe a flow chart along with it, as part of our LCIRP filing. And, so, I believe that's there. But that's, obviously, not in front of you right now.

So, as I'm understanding your question, you'd like to have that presented in this proceeding. I suppose I'm looking, either we can create one for this proceeding or -- as part of a record request, or perhaps the response to the record request would be to identify the specific portions of that LCIRP filing that have that information.

CHAIRWOMAN MARTIN: That would be a fine approach as well, whichever is less cumbersome for the Company. But my understanding is that this is sort of the "regular process", as opposed to the "LCIRP process". So, to the extent there are two processes, if you can submit the regular process here. If it's the same or parts of it are the same, and you can just identify that for us in the record request and point us to the other docket, we can certainly take notice of that.

MR. FOSSUM: Yes. I believe it's the same there, but we will confirm that, and sort of present the questions -- we'll take the question as in the alternative, either provide it or -- create it, provide it, or provide what exists in the other docket, but we will do that.

CHAIRWOMAN MARTIN: Excellent. Thank you.

WITNESS LAJOIE: Mr. Kreis, if I could just -- Mr. Kreis, if I could just supplement what Mr. Plante had said earlier.

MR. KREIS: Absolutely. But, before you do that, let me just say, to the extent it's germane, as the Company responds to the Chairwoman's record request, I really like the idea of tying things here into the LCIRP process. So, I would encourage the Company to follow those second of the two approaches that Mr. Fossum laid out.

BY MR. KREIS:

Q Sorry, Mr. Lajoie, to cut you off. I'd be happy to hear whatever else you wanted to add.

A (Lajoie) No, it was just kind of a supplement to what Mr. Plante was talking about.

The magnitude of the substation projects is such that there are multiple steps involved in this incremental project funding. The smaller projects, the distribution line projects, which I'm more intimately involved in the authorization for, generally, it's more of a two-step process. There's an initial funding request, to make sure that we've identified all the variables and, you know, gotten good estimates and so forth, and then the final funding request. So, it's really like a two-step process. The initial funding request is, you know, generally, well, it's generally less than ten percent of the project costs, just to make sure that everything's been identified so we don't get any surprises late in the process.

Q Okay. Moving on to Bates Page 019, again with reference to Exhibit 62, at that page, beginning on Line 7, the witnesses talk about "annual blanket projects". And they describe such projects as "projects that are high-volume and low dollar in nature", and they also note that "[annual blanket] projects are funded at a consistent level from year to year and utilize the same project names each year." That seems perfectly lucid to me. And there is, at Lines 12 and 13, a sentence that gives some examples of annual blanket projects, and the list is "new services, capital tools, obsolescence and asset renewal, line relocations, and service work."

And there's a few of those examples I don't understand. Again, it might just be my bad reading comprehension or lack of expertise. In that context, what do the witnesses mean by "new services"?

A (Lajoie) These are new service connections, connections to new customers to provide electric service.

Q So, "new service connections". That's exactly the kind of reading comprehension that I'm sorry I don't have.

And then, the next example you give are "capital tools". What are "capital tools"?

A (Lajoie) Tools with an individual cost greater than $500 each are capitalized. So, an example might be -- well, I guess I'm having a hard time coming up with an example, I apologize. Oh, I know one. A number of years ago -- a number of years ago we bought insulated chainsaws. So, it's like a hydraulic chainsaw on the end of an insulated stick, so our linemen could, you know, plug into the hydraulic system of the truck, and cut branches that are in contact with the line without being in danger of becoming a path for the electricity. And those units cost, I believe at the time, they were about $1,500 a piece. So, we purchased a number of those.

That would be considered a "capital tool", since each one of them is valued at over $500.

Q Thank you. Hopefully, Chairwoman Martin isn't about to leap in and make a record request to ask you to provide one of those, so that the Commissioners can look at them. But I totally misunderstood "capital tools". I thought, like when I saw that phrase, I thought "Oh, they're talking about like weird software they use to do capital planning." But you're talking about "tools that are capitalized."

And the very last example you give is

"service work". What do you mean by "service work" in the context of annual blanket projects?

A (Lajoie) The "new services", "new service connections" that we talked about first, involves both high voltage and low voltage. If we have to extend high-voltage lines to a transformer, and then, you know, a service from the transformer to the house. The service work at the end is exclusively low-voltage installations, from the transformer to the house. So, if we need to go out, if there's an existing transformer, and all we have to do is run a service to the house, that would go under the "service work - annual".

If a service has deteriorated, because a tree has been rubbing on it, and therefore needs to be replaced, it would be replaced under this "service work - annual". This is just low-voltage type stuff. It tends to be smaller -- it definitely is smaller dollar value per job than the "new service connections", which we talked about earlier.

Q Okay. I think this is my last question. I'm looking now at Bates Page 047. And this is probably a question for one of the rates and rate design witnesses, either Ms. Ullram or Ms. Menard. And this now reflects my lack of acumen when it comes to looking at numbers.

On that page, which is Page 1 of Attachment ELM/JAU-2, the very last column is "Percent", the last two columns are labeled "Proposed Annual Change", and the percent varies by rate class. From a low of "0.1", for Rate GV and LG customers, all the way up to "0.4", for Outdoor Lighting customers. And, again, I'm sure there are really good answers buried in some of the other spreadsheets that you provided.

But, just in general, can you explain why those percentages differ, given that I thought the step increase basically applied to all the rate classes equally?

A (Ullram) Sure. I'll take a shot at it. So, that -- we're combining all the rate classes in that, you know, Exhibit 62, Bates red Page 047 that you referred to. So, you're going to get slightly a little bit different of percentages between the two of them.

The more appropriate place to probably go to show how the rate design is done in accordance with the Settlement, meaning we have allocated to each of the rate classes an equal percentage, is Bates red Page 052. And, on that page, you'll see that Line 23 three shows the "Step 2 Average Percentage Change" is "0.86". And, so, in Column C to that spreadsheet, you'll see that, by multiplying Column B times Line 23, which is the 0.86 percent increase, you get a Step 2 distribution change based on the current distribution revenue. And, so, if you look at the last column, which is Column H, you'll see that everyone is right around that 0.86 percent.

You're not going to ever get exact, because, when you do rate design, you know, we're trying to hit a distribution target, total distribution target of $416.6 million. And we're never going to exactly get that, because we set the rates at five decimal places, and then, once you multiply everything out, so, you know, we're off about $10,000. So that kind of makes up for some of the differences in the percentages. You know, some are like "0.86", "0.87". But, overall, you can see that that's how we allocated equally among each of the rate classes.

MR. KREIS: Super. That's a really helpful answer. And I think those are all my questions.

I just want to brag that this is the first time I've done cross-examination without printing out a copy of the exhibit that I'm relying on. And, other than needing to rotate my head 90 degrees for a minute or two during the discussion that we just had, I pulled it off. So, I would just like to congratulate myself.

Thank you. Those are all the questions I have for this group of distinguished witnesses.

CHAIRWOMAN MARTIN: Congratulations, Mr. Kreis. I had that exact experience about a year ago. I was forced to go away from paper as well.

All right. Mr. Buckley, go ahead.

MR. BUCKLEY: Thank you, Madam Chair. And good morning, panelists.

I'm going to start my cross-examination today by introducing Exhibits 63 and 64. Staff submitted the two prefiled exhibits for this hearing are those two prefiled exhibits for this hearing. And I'm going to ask the panel to provide some foundation for those, so that they may be accepted into the record as full exhibits.

BY MR. BUCKLEY:

Q And the first question, as with all my questions today, will go to whoever on the panel feels most able to answer. But I believe the most likely recipient of this question is Ms. Menard.

So, do you recognize Exhibit 63, containing Bates Page 001 through 036, which is an audit by the Commission Audit Staff, now the DOE Audit Staff, of the Company's 2020 step, which covered plant-in-service during 2019?

A (Menard) Yes.

Q And did you, or someone in your organization, participate in this audit, providing data responses to the Audit Staff, as well as reviewing the preliminary audit recommendations?

A (Menard) Yes.

Q And is it correct that, at the hearing for the Company's last step adjustment, the Company had suggested that the results of the audit may be reconciled during the next step adjustment, the one that we are currently considering today?

A (Menard) Yes. As you'll note, the date was

February 1st that the Final Audit Report was issued. And, so, the intent was, between the time the Final Audit Report was issued and the time the next step was being filed, that we would have some discussions, and any Staff recommendations or findings would then be incorporated into the next step, this second step adjustment.

Q Thank you. And do you recognize Exhibit 64, which contains Bates Page 001 through 064?

A (Menard) Yes.

Q And these were data responses submitted by you or others in your company in response to requests issued by the DOE's Regulatory Support Division, is that correct?

A (Menard) Yes, I believe so. They don't have data request numbers on them, but I believe they are part of data responses.

Q Right. I should probably rephrase. Those were largely documentation relating to various projects, which are derived from data responses.

A (Menard) Okay.

Q So, they might not have the actual response themselves.

A (Menard) Okay.
Q And, now I'm going to turn to the substance of Exhibit 64. The responses are largely grouped by four topical areas, and I'm just going to ask you about your familiarity with those topical areas individually. Do you recognize Exhibit 64, Bates 001 through 007, which consists of a Supplemental Request for the Welch Island Submarine Cable Project?
A (Lajoie) Yes, I do.
Q Thank you. And this form was completed by you or someone in your Company, and provided in response to Staff Discovery Set 19, is that correct?
A (Lajoie) This form was definitely completed by someone within our Company. And I would have to allow that it most likely was submitted in response to a data request, yes.
Q Great. And do you recognize Exhibit 64, Bates Pages 008 through 053, which consists of Project Authorization Forms and Supplemental Request Forms for the Pemi Substation Equipment Replacement Project that we heard described earlier?
A (Plante) Yes.

Q And these forms were completed by you or someone in your Company, and provided in response to Staff Discovery Request Set 19, is that correct?

A (Plante) I'm sorry. Could you --

A (Devereaux) That is correct.

[Court reporter interruption due to audio issues.]

BY THE WITNESS:

A (Plante) Well, I was asking for a clarification of the question, because it didn't come through clearly for me.

BY MR. BUCKLEY:

Q Certainly. Do you recognize Exhibit 64, Bates 008 through 053, which consists of Project Authorization Forms and Supplemental Request Forms for the Pemigewasset Substation Equipment Replacement Project?

A (Plante) Yes.

Q And these forms were completed by you, or someone in your Company, and provided in response to Staff discovery requests in this proceeding, is that correct?

A (Plante) Yes. That's correct.

Q And do you recognize Exhibit 64, Bates Page 055

through 056, which describes an engineering issue that occurred during the Pemigewasset Project and how that issue was resolved?
A (Plante) Yes.
Q And this data response was completed by you, or someone at your Company, and provided in response to I believe a technical session data request, is that correct?
A (Plante) Yes.
Q And do you recognize Exhibit 64, Bates Page 057 through 064, which contains a Supplemental Request Form and a spreadsheet excerpt relating to the Company's Insurance Claims/Keep Costs Program?
A (Devereaux) Yes.
Q And these are responses --

CHAIRWOMAN MARTIN: Just a minute, Mr. Buckley. I just want to make sure that we got for the record, I believe Ms. Menard and Mr. Devereaux responded. Is that correct?

Mr. Patnaude, did you get that?

MR. PATNAUDE: I only heard Mr. Devereaux. I'm sorry. Thank you.

CHAIRWOMAN MARTIN: Ms. Menard, would

you repeat your response?

BY THE WITNESS:

A (Menard) Yes.

BY MR. BUCKLEY:

Q Great. And these forms were completed by you or someone in your Company, and provided in response to data requests from the Regulatory Support Division of the DOE, is that correct?

A (Devereaux) Yes.

MR. BUCKLEY: Given the foundation the Company has just provided, Staff moves to admit Exhibit 63 and 64 as full exhibits to this proceeding.

CHAIRWOMAN MARTIN: Any objection?

MR. FOSSUM: No, I suppose not. No.

CHAIRWOMAN MARTIN: Mr. Kreis?

MR. KREIS: No problem.

CHAIRWOMAN MARTIN: Okay. Then, we will strike ID on Exhibits 63 and 64 and admit those as full exhibits.

Go ahead.

MR. BUCKLEY: Thank you, Madam Chair.

BY MR. BUCKLEY:

Q Now, at a high level, would it be accurate to say that we are here today to discuss a step increase associated with plant-in-service in 2020, consistent with the Settlement Agreement approved by the Commission in the Company's rate case?

A (Lajoie) Yes. That is correct.

Q And that step represents an increase in the Company's revenue requirement of approximately $11.1 million, a number that can be found at Exhibit 62, Bates 040, Line 15, is that correct?

A (Menard) I believe that it's red Bates 041 on Exhibit 62. Yes, Line 15, $11.1 million.

A (Ullram) And I would just like to note that I brought this up earlier, but just to note again, that the actual incremental increase from last year, although the revenue requirements is approximately 11.1, the actual incremental increase over last year's revenue requirements is only around 3.6 million, because we had the higher revenue requirements last year, due to the fact that we were recovering the revenue requirements over seven months, as opposed to twelve months. So, incrementally, the increase is the 3.6 million that's identified on Bates red Page 052.

CHAIRWOMAN MARTIN: Mr. Buckley, I'll just ask you, when you reference a Bates page, if you can just give us the color as well for the record.

MR. BUCKLEY: Certainly. Certainly.

BY MR. BUCKLEY:

Q And, so, the increase we're looking at today is quite a bit below the $18 million cap described in the Settlement in the Company's full rate case, which is actually Exhibit 58 in this proceeding, I believe, and described at Bates Page 020. Is that correct?

A (Menard) I'm sorry. What was the exhibit? I don't have that available. I need to look it up.

Q Okay. So, the exhibit itself is probably less helpful for our discussion, although I think it is Exhibit 58. But, if you have background knowledge of the previous Settlement Agreement, there was agreement to, I think, an $18 million cap for this step adjustment revenue requirement increase, is that correct?

A (Menard) Yes. That is correct. And, on red Bates 041, Line 14, that's where we refer back to the cap per the Settlement Agreement of 18 million. Correct.

Q Great. And the revenue requirement requested here today is derived from approximately 124 million in plant that went into service in 2020, a number which can be found at Bates 024, Line 4, in Exhibit 62. Is that correct?

A (Menard) Correct.

Q And, as an aside, I know that the testimony touches on this briefly, but can you provide a little more detail for the discrepancy between the $18 million figure contained in the October 2020 Settlement and the actual year in plant-in-service in December 2020 being significantly less? Can you provide the reasoning for that, the basis?

A (Menard) Yes. The Settlement Agreement had used a forecast of the next three years at the time, based on our capital planning process, as to what would go into service in 2019, 2020, and 2021. And, at that time, we make projections as to which substations are going to go into service, which projects, how much is going to go into service for each line project, for each annual, all that kind of project-level detail. And that is a forecast that we submitted. And, so, we based the second step and the revenue requirement on that assumption.

In actuality, there were a handful of large substation projects that didn't go into service in 2020, which is causing the difference, the lower revenue requirement in 2020 than we had anticipated at the time of the Settlement.

And just to identify some specifics, we had had the Emerald Street Substation, which is a large substation, that did not go into service in 2020 as planned. It went into service in 2021, or is anticipated in 2021. There was an Eddy Substation Control House, again, that didn't go into service in 2020, and went into 2021. And there's a few of these larger substation projects that their in-service dates got delayed. So, that's the major cause of the variance.

Q And, so, would it be accurate to say that we will likely see a lot of those projects that had previously been projected to be requested for recovery during this step, actually being requested for recovery during the next step?

A (Menard) Yes. That's the intent.

Q But, nonetheless, those projects, and any others requested for recovery, would still have to fall within the initial agreed-upon cap from the Settlement Agreement, is that correct?

A (Menard) Correct. And there's -- there's ebbs and flows each year. So, there might be a few substations that didn't go into service this year, got shifted to 2021. And, you know, there might have been items in the 2021 Plan that got shifted out to 2022.

So, yes. Whatever goes into service in 2021 will appear in the next and final step adjustment. And it is capped at, I believe, an $11 million revenue requirement.

Q And, more broadly, would it be fair to say that, since the time of the Company's May 3rd filing of this step increase request, the Company and Staff have engaged in discovery, technical sessions, effectively conversations which attempt to break down any information asymmetries that might exist between the Company and its regulators, and maybe even at times within the Company, about the $124 million or so of plant in service and its associated revenue requirement?

A (Menard) Yes. We had a technical session earlier this month.

Q And, in your experience, this breaking down of information asymmetries and further due diligence on the behalf of the parties to the proceeding, is this generally accomplished through Staff's, or rather now the DOE, and other intervenors', including the OCA's, review of a sampling of projects which have been requested for recovery?

A (Menard) Yes.

CHAIRWOMAN MARTIN: Mr. Buckley?

MR. BUCKLEY: Yes.

CHAIRWOMAN MARTIN: For clarification for the Commission, can you please explain, when you say "information asymmetries", specifically what you're talking about?

MR. BUCKLEY: Yes. So, I would suggest that, in regulated industries, there is often an information asymmetry observed between the regulated and the regulator, in that what is initially filed, or at least one example, is what's initially filed as the request for recovery is, yes, supported by rather extensive testimony and justifications for the request itself. But, for example, there are further records of the company or supporting materials that help to inform whether each project and, more broadly, the Company's overall approach to investments, is actually an approach which results in prudent investments and just and reasonable rates.

CHAIRWOMAN MARTIN: Okay. Thank you. So, you're essentially describing a global issue related to regulation, as opposed to a specific issue with this utility?

MR. BUCKLEY: Yes. Exactly.

CHAIRWOMAN MARTIN: Thank you.

MR. BUCKLEY: And, so, for some context here, Staff's approach to this step adjustment hearing, now that the foundation for exhibits has been laid and general overview provided, is that we'll be walking through a small sample of projects reviewed by the Regulatory Support Division, and you'll have to excuse me if I occasionally misstep and use the phrasing of "Staff", and provide some further discussion of various data requests, as well as the results of the last step's audits. And then turn things over to the Commissioners, and then we'll provide any recommendations at closing.

BY MR. BUCKLEY:

Q And we will start with the Welch Island Submarine Cable Project that we heard Mr. Lajoie, I believe it was, speak about earlier.

So, in the attachments, we saw this initial $360,000 project estimate. Mr. Lajoie, can you tell us what the basis was for that $360,000 estimate --

CHAIRWOMAN MARTIN: Excuse me, Mr. Buckley. Would you please provide the Bates Page number, so that we can return to it?

MR. BUCKLEY: Certainly. It was Exhibit 62, Bates 026, red Bates 026, I believe it was, Line 7.

CHAIRWOMAN MARTIN: Thank you.

MR. BUCKLEY: And the "360,000" can be found at Column I.

BY THE WITNESS:

A (Lajoie) The initial request for $360,000, as you pointed out, was submitted on a Project Authorization Form completed in 2016. I believe your question is "What was the basis for that

$360,000 figure?" And I cannot answer that question. The people involved in submitting that original request no longer, any of them, no longer work for the Company. So, I don't know what that was based upon. And, unfortunately, it was not itemized in the original Project Authorization Form what the cost basis was based on. That is required as part of the Project Authorization Forms at this time, but apparently was not back in 2016.

BY MR. BUCKLEY:

Q Uh-huh. And, so, the 2020 plant-in-service, which has been requested for recovery here, am I correct in observing, at Column H, that it is about $1.6 million?

A (Lajoie) Yes. That's correct. 1.575 million, "Plant in Service", Column H. Yes.

Q And Column M, "Actual Project Life-to-Date Costs", is something that's just a bit more than that, right, 1.883 million?

A (Lajoie) That's correct.

Q And this is a project which -- can you describe the project for me more broadly? For example, the number of customers that will be served from it?

A (Lajoie) Yes. This project was actually replacing two pieces of submarine cable in Lake Winnipesaukee, from the mainland to Welch Island, from the mainland to Lockes Island. The cable to Lockes Island was about 1,100 feet, and the cable to Welch Island was 5,400 feet, so just over a mile.

The original installation to Welch Island was completed in the 1940s. I was not working for the Company at the time. There were three cables installed originally. But, over time, at least one of those cables had failed. The remaining cables were deteriorated. Most specifically, the piece we could see at the edge of the water, both on the mainland side and on the island side, wave action, action on the ice moving, as ice-out happened, had scraped the cables across the rocks along the edge. So, I know that the neutral cable, the neutral for that cable, which is spirally wound around the outside of the cable, had deteriorated, and certainly was a concern of having an open neutral to those customers on the island.

I know the Lockes Island cable at times had failed and been spliced, so they had had to -- the riser pole is where the cable transitions from overhead to underground, and then, on the island, it transitions from underground back up to overhead. As you know, that, in order to splice that cable, because it was at a depth that could be reached, they had to actually pull cable back from the riser pole, so the riser pole was getting shorter as the cable went up, and that was considered to be an unsafe condition.

So, the two cables really were in bad shape. So, the decision was made that we really needed to replace these cables.

I don't think I have information in front of me as far as the number of customers on the island. As I said, these are both existing cables that were being replaced. So, it wasn't that, you know, we were installing a brand-new cable to feed brand-new customers. This was replacing existing assets.

Q And, so, maybe I can direct you to Bates Page -- Exhibit 64, Bates Page 005.

A (Lajoie) Okay. I'm there. Yes. Ah, okay. Yes. There you go. There's 42 customers on Lockes Island. And Welch Island has 58 customers. That's in the "Overall Justification" section on Bates Page 005 of that attachment.
Q And, so, forgive my law school math here, so let's say approximately 100 customers is who this project is meant to serve, is that correct?
A (Lajoie) Yes. That is correct.
Q Okay. Great. And do we know if these customers provided any sort of contribution to this project?
A (Lajoie) No, they did not.
Q And is it possible that some of these customers received compensation for easements the Company may have had to acquire during the course of this project?
A (Lajoie) I was not able -- I did some research on this, I was not able to find any information on the easement of -- on any easements which were purchased on the island side. I do believe an easement was purchased on the mainland side of the longer of the two cables.
Q Okay. And do you think that, if the Company's

projected costs were closer to the actual final costs, rather than the 360,000, would the Company have, pursuant to its TD190, considered -- been able to consider other alternatives that are somewhere between that final cost estimate and the $360,000 cost estimate?

A (Lajoie) There were alternatives considered, none of which were deemed to be viable. Providing electric service to islands is always a difficult situation. You know, again, this was existing customers. So, we couldn't just tell them "I'm sorry, you don't have any power anymore, because the cable feeding the island failed." I believe we're under an obligation to continue to serve.

Alternatives, such as a large generator on the island, were dismissed -- or even a series of small generators on the island, was dismissed due to the environmental concerns. Stationary, permanent generators do require air permits. Of course, transporting fuel to the island, to keep these generators running and so forth, would have provided, you know, presented its own difficulties, and, again, environmental concerns.

I don't believe a large enough solar

installation could be installed on the island to provide permanent power. It clearly would need to be coupled with some sort of an energy storage system, which significantly increases the cost of such an alternative.

So, you know, the possible solutions, possible alternatives, none of them were deemed to be viable alternatives to simply replacing the cable, to ensure that these customers had continued electric service. The installation was done in a manner that prevented some of the physical damage that we've seen to the existing cables. For example, conduit was run out to a distance where I believe it was 20 feet below the surface of the water, and the cable was run through the conduit. So, the icing action that I had mentioned earlier and wave action wouldn't deteriorate the new cable. It's protected in conduit buried in the ground. It also protects it, you know, in general, from boat anchors and things like that, fishing hooks and so forth.

So, the installation is improved over what was there from the 1940s. And the replacement was deemed to be the best alternative to maintaining electric service to these customers.

Q And do you know if the alternatives considered were compared to the $360,000 initial cost estimate or the -- I think it was the supplemental request of $1.9 million?

A (Lajoie) In either case, no matter which one you're comparing it to, the environmental considerations would continue to weigh heavily against the alternative. So, the original Project Authorization Form included the alternatives. And, yes, that was looking at the 360,000. But, when the supplemental was presented, the discussion continued on, saying "Isn't there another way that we can do this?" And no alternatives were considered to be justified, even at the significantly higher cost of the $1.9 million.

Q And, so, I am looking at Bates Page 006 of Exhibit 64. And I see a single financial sentence talking about alternatives that were considered.

Is that the extent to which alternatives were considered for this project?

A (Lajoie) "Distributed generation" can refer to a large number of things. It could be traditional gas- or diesel-fired generation. It could be solar. I am sure that a large wind turbine was not considered as part of the possible alternative. But, you know, that could also be distributed generation.

So, the term here "Install distributed generation", you know, again, would be very costly and not an appropriate avenue to provide backup, applies to both traditional fueled generation and solar, certainly.

And, again, the solar requires a significant amount of real estate, which, as you might imagine, is at a premium on an island property, that's been divided up into a significant number of lots. But there's also the storage system that would have to go along with it, a large battery storage system in this particular case, since I'm assuming they couldn't get a flywheel installed. That, you know, just, again, significantly adds to the cost, and at that point is not, as the sentence says, "not an appropriate avenue."

Q And do you know if the Company conducted an actual cost-benefit analysis of, for example, a solar plus storage option, or instead said, in its judgment, "it's such an order of magnitude off, an analysis wasn't warranted"?

A (Lajoie) No, no specific cost-benefit analysis for those alternatives were documented. But I am confident that, yes, in the Company's judgment, it was considered to be cost-prohibitive and not an appropriate alternative.

Q Okay. Now, I am going to move on to the Pemigewasset Substation Project that was discussed earlier as well. And just to give us another basis in the record, is this the project identified at Exhibit 62, Bates 060 -- Bates 026, sorry, Line 19, is that correct?

A (Plante) Yes.

Q And, so, we heard a little bit earlier about the somewhat significant difference between the pre-construction estimates and actual final cost. But can you just very briefly tell me -- give me a quick summary of what that was again?

A (Plante) In terms of dollars or history?

Q In terms of history, the basis for that variance.

A (Plante) All right. So, as I mentioned earlier, this is one of those projects that was authorized at our prior authorization process, where it received full funding prior to having any, you know, detailed engineering performed.

So, in 2017, this project was initiated and evaluate -- the alternatives were evaluated, and ultimately a project to replace the existing transformer with a new 62 MVA transformer was raised up. So, in 2017, RLC, who is a consulting engineering firm that we had contracted with to assist with project estimating, prepared a project estimate for the replacement of the existing transformer with a new one as *[indecipherable audio]* --

[Court reporter interruption due to audio issues.]

CONTINUED BY THE WITNESS:

A (Plante) Okay. So, they developed a project estimate for the replacement of TB88, which is the existing transformer, with a new 62 MVA transformer unit, as well as the replacement of two oil circuit breakers with new vacuum circuit breakers, and all of the associated protection and controls for that equipment.

So, they used industry-standard software to prepare that estimate. So, it's more a menu-based or cafeteria-style estimating, but it is an industry software.

So, in February of 2018, that estimate was used as the basis for a full funding project authorization that was presented to EPAC and approved for $4.1 million, and at that time had a planned in-service date of June 2000 --

CHAIRWOMAN MARTIN: Just a moment. Mr. Plante? Mr. Plante, can you hear me?

WITNESS PLANTE: I'm hearing you.

CHAIRWOMAN MARTIN: Let's go off the record.

[Brief off-the-record discussion ensued.]

CHAIRWOMAN MARTIN: Okay. Why don't we take a break now, until about 10:50, and let Mr. Plante work out his issues with bandwidth. We'll be back at 10:50.

(Recess taken at 10:38 a.m. and the hearing resumed at 10:51 a.m.)

CHAIRWOMAN MARTIN: So, let's go back

on the record. Go ahead, Mr. Buckley.

MR. BUCKLEY: Thank you, Madam Chair.

BY MR. BUCKLEY:

Q So, I think we were just discussing the reason for the cost increases associated with the Pemigewasset Substation Project. Is that correct, Mr. Plante?

A (Plante) That is correct.

WITNESS PLANTE: And I don't know if, Mr. Patnaude, you want to bring the group back up to where we were when I faded away. And, again, my apologies for the bandwidth problem.

(Whereupon the Court Reporter read back the last sentence of the answer before the audio bandwidth issues occurred.)

WITNESS PLANTE: Thank you, Mr. Patnaude.

CONTINUED BY THE WITNESS:

A (Plante) And, at that time, there was, along with that funding authorization, there was a plant in-service date of June of 2019. As I mentioned earlier, at that time minimal engineering on the project had been done.

And the thought at that time, regarding

the scope of the work, was that there would be sufficient space in the existing control building that would be vacated by some of the removed cabinets to place the new cabinets in the existing control building. So, at that point, we hired a -- excuse me -- a design engineering firm, that was RLC Engineering in this case as the design engineer as well, and embarked on the effort to fully define the project scope. And, in July of 2018, that detailed project scoping document was completed -- well, actually, I'm sorry. We did the scope document internally, and then in September of 2018 is when we issued the purchase order to RLC Engineering for the detailed design.

And then, in October 2018, we actually went pencils down on the design for this project, due to some constraints in the distribution budget. As you know, we try to, you know, execute our distribution budget as close to the approved trustee budget as we can. So, we make, you know, decisions near the end of the year on what things should be proceeding and what things should be slowing down based on that.

So, we picked back up with the engineering in the beginning of 2019, and completed a conceptual design for this project. And then went to the site with the design team and some key construction resources, to review those design documents, based on the existing field conditions and get some feedback. And this is where we determined that there was a need to expand the existing control building to safely house all of the necessary equipment for the protection and controls of the new transformer and circuit breakers.

So, we announced this in April of 2019, along with a plan to wait until the construction pricing was available before submitting a request for additional funding, because at that time we really didn't understand what that full impact was going to be, because we needed to go and complete the design for the control building expansion and determine what that cost was going to be.

And, in August of 2019, we completed the Site Plan Application with the Town of New Hampton Planning Board. So, we needed to, because we were doing that expansion of the control building, that required us to modify our existing site plan, which was on record with the Town of New Hampton. So, that was approved in I want to say October. And then, we commenced the civil construction in December of 2019, which included the control building foundation.

It wasn't until April of 2020 until we received the competitive bids for the electrical construction for the project, along with the testing and commissioning proposal. So, at that time, we updated the estimate for the project, based on these knowns, which previously had not been knowns, they were merely assumptions, and drafted the Supplemental Funding Request, which we submitted in June of 2020.

So, you'll notice in the -- in the exhibit, on row -- I guess red Bates 026, Row 19, there are actually two Supplemental Funding Requests identified there, when, in reality, we only approved one Supplemental Funding Request, this one that was presented in June of 2020 requesting an additional $2.7 million. It was approved by the EPAC. It did have a condition associated with it, that we present the supplement to an Executive Review Board.

CHAIRWOMAN MARTIN: Mr. Plante?

WITNESS PLANTE: Yes.

CHAIRWOMAN MARTIN: Oh, you're back. We lost your video for a moment. Go ahead.

WITNESS PLANTE: Oh. Sorry.

CONTINUED BY THE WITNESS:

A (Plante) So, we did have a condition that we had to present the Supplemental Funding Request to an Executive Review Board, which consisted at the time of Bill Quinlan, Joe Purington, Aftab Kahn, and a couple others. And this is typical for any project that has a value greater than $5 million. So, it's not specific to this. It's just because the value was greater than 5 million.

So, that meeting didn't get scheduled until October 15th, due to everybody's schedules, summer vacations, all of that kind of stuff. In the meantime, we continued with our construction.

And, on September 19th, we were in the process of energizing the new transformer TB88. And, during that energization process, there's a lot of testing that gets involved with that. And that testing detected a phasing error in the Synch Scope, which would limit our ability to use -- to effectively use the transformer. So, we decided at that time to abort that energization process and figure out what was going on with that.

So, you know, that launched us into a process with a lot of internal engineering resources to evaluate what the situation was, determine a path forward, and then we had to get RLC Engineering involved again to perform some additional engineering to correct that issue, which ultimately we did. And, on November 1st, we were able to get that transformer successfully energized.

It equated to an approximately six-week delay in that transformer energization. So, while all this is going on, we had completed our executive review, and this particular supplement began its route for final approval in the PowerPlan system. And, due to this issue, and at the time we still weren't fully aware of what the cost impact that was, we decided to halt the approval of that supplemental request, in favor of resubmitting a new revised version that incorporated any of the cost changes associated with this revised engineering for the transformer.

So, and in any event, that all then kind of got itself figured out in the latter parts of 2020. And then, in early 2021, we submitted the revised Supplemental Funding Request for about $3.7 million, which was approved by EPAC on April 14th. And this one -- this version does cover all of the increases from the previous version of the supplement, as well as additional costs that were incurred during the correction of that Synch Scope phasing issue.

And that's kind of how we got to where we are today with this project.

BY MR. BUCKLEY:

Q That's very helpful. Thank you, Mr. Plante. And, so, that Supplemental Request Form you mentioned, that I think it's the final one, if I could ask you to turn to Exhibit 64, Bates Page 037.

A (Plante) I'm almost there. Okay. I am there.

Q And, so, am I correct in understanding the "Prior

Authorized", is that first column we see, at the bottom it's totaling about 4 million, and the "Supplemental Request" is the 3.6 or 3.7 million that you mentioned before?

A (Plante) Yes.

Q Great. Can you tell me why the indirects have gone up almost tenfold, but the directs have only gone up by, ballpark, about 60 percent or so?

A (Plante) Yes. Sure. So, in the initial -- well, it's called "prior authorized" here, you'll notice that the "Capital Additions - Indirect" value is just over $200,000. This is a value that came from the RLC estimate that was done in 2017. And, at the time, RLC wasn't very well schooled, I guess for a lack of a better term, on how to apply our overheads to the actual direct costs for the project. So, the actual indirects that were part of the prior authorized were inadequate at that time. They weren't properly applied to that estimate. And the first -- the version of the first Supplemental Funding Request was addressing a lot of that issue.

Q Okay. And, so, it sounds like there was something of an accounting error or accounting

projection error on behalf of RLC. You also mentioned the error during "phasing", I think was the term you used?
A (Plante) Energization, when we were energizing the transformer.
Q And, so, at least the energization error, did that result in incremental project costs?
A (Plante) Yes, it did.
Q And, so, RLC is an independent contractor of Eversource's, right? External to Eversource?
A (Plante) That's correct.
Q And did Eversource take any action to try to recover some of those incremental costs from RLC or maybe an insurer or something along those lines?
A (Plante) We did -- We did not seek any insurance claim, *per se*, through RLC. We do have contracts that have been negotiated with all of our engineering vendors, we have a lot of them, that limit the amount of liability that they are liable for. So, in this case, they did complete all of the additional engineering at their own cost, but their contract doesn't make them liable for the -- I don't know if the word is correct,

but I would say -- I'd call them "consequential" damages.

And we do have our own engineering folks who have a role in reviewing and whatnot the engineering deliverables. So, you know, there's -- it's very difficult to pinpoint, you know, exactly which person made which mistake, and whether they should have caught it at that point in time.

But we do have a process where, you know, the design engineer is supposed to create the design and perform an internal review, they provide it to us. We perform our review before it goes to construction. We are all human. Sometimes we don't catch all of those things until later on in the process, which is exactly why we do testing.

Had we not done this testing, we probably would have energized the transformer and created a -- and maybe failed the transformer. You know, we test everything before we energize it. And, in this case, that testing process did exactly as it was designed to do, it detected a wiring error, and helped us figure out how to

correct it.
Q And, so, it sounds like that testing process limited what I think you just referred to as any "consequential damages" that occurred to something that's much smaller?
A (Plante) Yes.
Q But, if I were looking to better understand those consequential damages, I assume it would probably be something less than the difference between that -- that number at Bates -- what was it? -- 037, which was $3.6 million, between the initial and the final supplement, right?
A (Plante) Well, if we're talking -- are we talking just about the impact of the aborted transmission -- transformer energization or are we talking about the whole change?
Q Let's talk --
A (Plante) Because the 3.6 includes a lot of other stuff that transpired prior to the transformer energization issue, and would normally have been covered in our current project funding authorization process, where we don't seek full funding until we have, you know, the lion's share of our variables and assumptions nailed down.

Q Let's talk exclusively about the transformer energization issue. Where would I look to better understand what the dollar figure is associated with that?

A (Plante) Well, what we did is provided an explanation of the difference between that first supplement that we did not fully approve, and the subsequent -- the subsequent supplement that was approved. And part of that response that we provided included a comparison between those two. It adds up to about $900,000, including overheads and whatnot. So, that kind of breaks it down, based on kind of a high-level line item process. So, there's a little bit of engineering, a little bit of materials, significant amount of construction, and testing and commissioning.

And that, you know, that all gets compounded by the cost of time and delays, people on-site for a longer time than planned, and those types of things.

Q And how about the cost associated with the initial engineering design work? I think I heard you say that that was -- that the contractor had, in fact, eaten those costs in some way, shape, or

form, because that design work was --
A (Plante) That is correct.
Q And, so, hearing that, I would have thought that maybe there would be some sort of, at Bates Page 056, where it says, I guess you could say Line 16, where it says "Reimbursable", there might be --
A (Plante) Hold on. Page 56?
Q Yes. This is the variance sheet that you were talking about before. It has, at the bottom right, the "911,000".
A (Plante) Okay. I'm there now. You can actually back up with your question.
Q Yes. Certainly. So, I think I just heard you say that the third party contractor had to -- wasn't able to charge for or had to eat, in some other way, shape, or form, their -- the costs of their initial work, because it turned out to present some problems in the actual project. Is that accurate?
A (Plante) Yes, kind of. Well, what I was saying, they didn't reimburse us for the work that they had done previously. They just didn't charge us for their ongoing effort to make any corrections

or revisions to that, to those design documents. So, it wouldn't show up as a reimbursable.

Typically, reimbursables are, at least as far as I'm involved, dealing with like third party generators, when we're maybe doing some work for -- on one of our stations to accommodate an interconnection, that the costs that we incur for them would be recovered under the Line 16 as a reimbursable. That's kind of where that would show up.

And, even if we were to get a -- like an invoice credit, which we often do, it would show up -- it wouldn't show up as a reimbursable, it should show up on the actual line item where the charges originated from. So, you know, if it was an engineering credit, it would be on Line 4. So, it would just show what the total value is, not a specific value for a credit.

Q And Line 4 appears to actually go up between the 2020 Supplemental Request Form and the 2021?

A (Plante) Yeah. That's internal labor. We had a lot of involvement of our internal engineering folks when this happened. So, that's Company labor.

Q And, so, you also described the other cost increases, those which are not directly attributable to this error from your third party engineer. Can you just go through very, very briefly some of those, the basis for those cost increases, and why they're different from this incremental cost? I think some of the Project Authorization Forms -- go ahead.

A (Plante) So, if I understand your question correctly, you're looking to understand what the costs were from the June 2020, which was the one that was halted? Is that --

Q Yes. So, in the Project Authorization Forms, I recall discussion of Smart Grid enhancements and animal protection devices and whatnot --

A (Plante) Okay.

Q -- that were not included in the initial Project Authorization Form, and are part of the basis for the cost increase.

A (Plante) Yes. I'm with you now. Thank you. So, in the initial supplement included additional scope that was either not initially intended or not specifically included in the estimate. So, in addition to the expansion of the control house, which was kind of the big ticket item from a direct cost perspective, there were additions to the scope for animal protection at the substation, which is installation of kind of dielectric devices on bushings and insulators and whatnot, that would prevent, you know, squirrels and birds from creating outages at the substation.

You know, during the execution of this project, after it was fully funded, our company initiated a program to install animal protection at many of our substations, Pemi included. And what we did in this case is we included that scope in this project and covered it through the Supplemental Funding Request. Well, in retrospect, probably would have been wiser and cleaner just to open up a new project at Pemi referencing the program to cover that cost. Then it would not be, you know, looking like the original project just missed something, when, in fact, that wasn't something that we were doing widespread at the time this project was initiated.

Q And, so, Mr. Plante -- sorry to interrupt.

A (Plante) Yes. Go ahead.
Q But you mentioned the "control room".
A (Plante) Yes.
Q Can you tell me why the control room limitations weren't something that the Company would -- either the Company or its third party contractor, if this difference is attributable to the third party contractor, would have been aware of from the outset of the project?
A (Plante) So, they're aware of the existing footprint of the control building, as well as the cabinet layout in the control building. The consultant wasn't involved at this time. This was internal engineering, and they're, you know, they're assembling their assumptions for the project. And they, at the time, were thinking "Oh, we have X number of new cabinets that we're proposing, and it looks like we can squeeze them in in these places. So, we will initially not plan on expanding the control building." So, that was -- that was how that was considered when the initial estimate in funding was prepared.
Again, engineering hadn't been done. We didn't have all of the application diagrams

and elementary diagrams, protection and control systems prepared. So, we didn't have the full knowledge of exactly how many control cabinets would be required, and how well they would fit in that existing space.

So, once that knowledge became available, we took it to the site and tried to, you know, evaluate the constructability of that, and whether it was, in fact, going to be constructable in a safe fashion. And, at that time, it was determined that we would be way better off to expand the control building.

That was a decision that was made by engineering and construction, you know, all of the, you know, the experts in the field, based on knowledge, not based on assumptions. Does that make sense?

Q Yes. That's very helpful, Mr. Plante. So, I think maybe we can move now to just very briefly the Rochester 4 kilovolt conversion, which I think you will find at Exhibit 62, Bates -- red Bates 026, Line 13. Is that correct?

A (Plante) Yes.

Q And can you tell me why this project appears, according to Column F, to have a first in-service date of "2018". But, then, if you move over all the way to the right, at Column U, it appears to have a full in-service date that will not occur until "2021"?

A (Plante) Yes. Certainly. So, this particular project, and it's entitled "Rochester 4 kV Conversion", I'm not a distribution expert in the Rochester area, but a large portion of the Rochester distribution system, well, has been at 4 kV for a long, long time. And this project aims to upgrade that distribution service voltage to I want to say "12 kV", and hopefully correct me if I'm wrong, Lee. And that's a stepwise process. In order to do this, it takes, you know, a lot of time and effort on the behalf of roadside distribution line crews, as well as substation construction projects, for instance, the Twombley Street Substation. There's an existing 4 kV substation there that needs to be rebuilt to 12 kV, before it could serve the distribution lines that were directly connected to it at 12 kV.

So, the way the project has unfolded is

you started working on these distribution circuits in a piecemeal fashion, opening up work orders for one circuit at a time or a portion of a circuit, and creating -- going out there, developing work packages, and assigning crews to them to complete the work. So, as each of these work orders is completed, and the customers are now being served at that new voltage, those work orders can go in service, because they are performing their intended function.

Currently, I think we have 21 work orders that have been opened, they're not all still opened. Many of them are in service and closed out by now. But we do still have a number of them that are still in, you know, either in design or construction. And the intent is that we would have the remainder of this Rochester 4 kV conversion completed by the end of this year. And that's why you see in-service in various years for this project.

Q And, to be clear, that which is requested for recovery within this step is now already used and useful and energized and providing service. That's correct?

A (Plante) Yes. That's correct. So, the work order would be placed in service upon completion of the last customer being converted on whichever work package they're referenced. So, once that's done, the work order gets placed in service, AFUDC stops, and we begin the close-out process.

Q Great. So, now, I want to turn to the Audit Division's February 2021 audit of the Company's 2020 step filing from last year. Focusing on two specific issues that were raised by Audit, which from the Regulatory Support Division's perspective, appear yet unresolved, and, in fact, do reoccur within this step request. And those would be the characterization of load tap changers for accounting purposes, and the Company's accounting treatment of damaged property that may be reimbursed via a third party's insurance company.

So, starting with the load tap changer, can you please briefly describe what a "load tap changer" and/or "controller", I think I saw it referenced as both items within the audit and filing, can you say what the function of that device is?

A (Plante) You want that, Lee?

A (Lajoie) Yes. I'll take that. A substation transformer, especially newer ones, have, in addition to the transformer, there is a separate mechanical piece of equipment that allows you to regulate the voltage coming out of that transformer within a certain range, generally plus or minus 10 percent. That device is called a "load tap changer". It changes what are called "taps" within the transformer, changes them under load, hence the name "load tap changer". Associated with that load tap changer is a control, which monitors the voltage, it has program settings. And, as long as -- if the voltage goes outside those limits that are programmed into the control, it adjusts the taps such that it will change the voltage coming out of that transformer. That's a "load tap changer". The "control" is actually the device that you're referring to, that was discussed in the audit, and in some of our tech sessions.

Q And can you tell me what the average useful life of a load tap changer control is?

A (Lajoie) I'm not sure. Does somebody else want to take that one?

Q I can rephrase, if that's helpful. Is it common for a load tap changer controller to be replaced ahead of the retirement of the transformer it's attached to?

A (Lajoie) Yes. That is not an uncommon situation. Load tap changer controls historically have been mechanical devices with electromechanical relays. Modern load tap changer controls are solid-state devices with solid-state relays, provide much more robust options, as far as the settings that are programmed into that control, and provide additional capabilities, such as the ability to remotely monitor what that tap changer is doing, and remotely adjust the settings and the response of the tap changer.

Q And, if you turn to Exhibit 63, Bates Page 021, it describes a disagreement between the Company and the Audit Division about whether these load tap changers represent individual units of property, in which case the Company might properly capitalize them and recover them within the step, or whether they are simply replacements, maintenance of property that was already initially capitalized, in which case the audit recommends they should instead be expensed, rather than capitalized. Is that correct?

A (Lajoie) I am familiar with those discussions, but was not party to it.

Q And cited within the audit is an Eversource policy memo developed in March 2012, is that correct?

A (Lajoie) Yes. I believe that's correct.

Q And, so, prior to 2012, it sounds like the Company had treated those devices in the manner that Audit recommends, and in a manner which Audit argues or observes is consistent with FERC accounting?

A (Menard) I believe it's an interpretation issue. And there is a disagreement in interpretation. So, I'm not sure it's a FERC issue. It's an interpretation of FERC guidance.

Q And, to follow up there, prior to that March 2012 memo, the Company had interpreted that FERC accounting or that device differently, is that correct?

A (Menard) I believe that's the case. I don't have the background in front of me, the prior to 2012.

But, in 2012, there was a change in policy, an accounting policy. And the accounting memo that was provided as part of Audit states that "LTC controls and relays are recognized as retirements or units of property, and therefore they can be capitalized separately, and they're not a maintenance item."

Q And would it be accurate to say that the Audit Staff cites the FERC rule at Exhibit 63, Bates 020, which states "When a minor item of depreciable property is replaced independently of the retirement unit of which it is a part, the cost of replacement shall be charged to the maintenance account appropriate for the item." Is that correct?

A (Menard) Yes.

Q And is it correct that, in this step, which examines 2020 plant-in-service, there were, in fact, load tap changers that were capitalized, rather than expensed?

A (Menard) Yes.

Q And, if you could turn to Exhibit 60 -- the initial filing, which was Exhibit 62, I believe, Bates Page 026, red Bates Page 026, Line 27,

please?
A (Menard) Yes.
Q Is it correct that there appears to be a project related to load tap changer controllers that's approximately requested for recovery of $463,324?
A (Menard) Yes. That's correct.
Q And, if you could also turn to Bates 028, Line 15, and that's -- I think it's red Bates Page 028, but I will double check.
A (Menard) Yes. That's correct.
Q There is another project which involved load tap changer controllers. I think that the load tap changers were less than the entire project in this instance, is that correct?
A (Menard) I believe you're referring to Bates -- oh, sorry, yes. On Bates red 028, Line 15?
Q Yes.
A (Menard) Says "Annual Substation Projects". So, there's many, many individual smaller projects within this one. And there is a work order that has a load tap changer within that project.
Q And is it accurate to say that, of the load tap changers, they represent approximately $40,000 of the overall costs?

A (Menard) Yes. That's correct. And, while it's not shown here in this exhibit, we did explore that within our technical session.

Q Great. Thank you. And, if the Commission were to agree with the Audit Division that these equipment replacements should be characterized as an expense, would they be -- would they still be eligible for recovery in the step?

A (Menard) No. Expense is not included in the step.

Q And are there any other major differences between characterizing these equipment replacements as an expense, rather than a capital investment? For example, if they were characterized as an expense, rather than capitalized, would the Company still be eligible to earn a return on those assets?

A (Menard) No. You know, presumably, if these were included as an expense item, presumably they would have been in our cost of service, which is, you know, the basis for our distribution rate. But the policy that we had in place, or we have in place currently, that would have been the basis for our cost of service, and our revenue requirement had these as capital units, and therefore not expense. So, they're not in our revenue requirement and cost of service.

Q Thank you. Now, I want to turn to the last subject I want to touch on today on cross-examination, which is the subject of damaged property/reimbursables, I might call it. Now, if I can ask you to turn to Exhibit 63, at Bates Page 003, there appears to be some degree of disagreement between the Company and Audit Staff about whether the Company, in several related accounts that should be able -- let me restart here. There seems to be a bit of disagreement between the Company and Audit Staff about whether, for several related accounts that cover insurance, whether the Company should be able to recover total capital additions related to damaged property prior to the receipt of any insurance reimbursable, or rather the Company should only be able to, at least in the initial year, only recover net plant additions.

Am I getting that correct? I might not be.

CHAIRWOMAN MARTIN: Mr. Buckley, can

you point me to the Bates page again? I apologize. I didn't hear you when you said it.

MR. BUCKLEY: Oh, yes. It is Exhibit 63, Bates Page 003.

CHAIRWOMAN MARTIN: Thank you.

BY THE WITNESS:

A (Menard) I'm not sure you're characterizing it correctly. During the audit, there was a question about how reimbursements are applied, and the specific accounting associated with that. And, in Audit Issue -- give me just a second to find it -- in Audit Issue 1, that begins on Bates 015, there was -- there was a few different issues going on. One was asking questions about the actual Project Authorization Form itself, and understanding how the reimbursements are applied to what is authorized. Then, there was some questions about how reimbursements are applied. And then, also questions about how reimbursements are recovered, and following the accounting for all of that.

And Bates Pages 015 through 018, and then again on Bates Pages 029 through 035, were responses to try to explain the accounting associated with reimbursements. So, essentially, and we did go through this in a bit of detail in the last step hearing. And, you know, we explained the process that, when damage occurs, crews go to repair that damage. So, let's take an example where a car hits a pole. If the -- if a police report is created, and therefore the damager of the property is known, you know, our crews make the repairs, whether or not we know the damager or not, our crews make the repairs. If the police report is filed, and there is a name associated with who damages the property, our administrative staff will go and request that police report, and then we know who to bill the damage to.

So, at the time, when we find out all the information, we create a bill, essentially, and send that to the damager of the property. At the time that bill is sent, a credit is applied to the work order immediately, for the full amount. That work order is then closed, the process is then -- eventually closed, the process is completed. And there is a separate process that occurs to actually obtain that, that billed amount, from the damager, either from the damager itself or from the insurance company.

We may or may not receive 100 percent of that reimbursement. We may not receive it in a timely manner. There are times where there's payment plans that are offered to the damagers. So, the recovery of those reimbursement claims occur over time. But the work order itself, and the amount that's included in this revenue requirement, is credited fully for that amount billed.

So, in the Audit Report, there were questions around the process, on trying to understand where the reimbursement credit or that offset shows up, whether it shows up in plant additions as an offset, or accumulated depreciation. And, so, the response tries to explain that that credit is not an offset to plant additions. It's actually a credit to cost of removal. And, so, therefore, the addition amount is not reduced. It does flow through accumulated depreciation, which therefore reduces the revenue requirement.

So, you know, the Company responded to

the audit request. There was no further action on the Audit Report. There was no further discussion. There was, in our last step adjustment, there was an acknowledgment that this was still an open issue to be worked through, and that this could be resolved through or further understood through the business process audit, which I believe should be starting within the next month or so. And, so, we could further investigate that at that time as well.

Q And, so, if I were looking to see, within the instant Petition, for where this issue is, would I be accurate to say it is at Bates 028, red Bates 028, Line 38, and the value we're looking at requested for recovery is Column G, which is 2. -- about $2.6 million?

A (Menard) In Exhibit 62?

Q Yes. Sorry. Exhibit 62.

A (Menard) Yes. Yes, that is correct.

Q And, so, that amount is the gross of the plant that the Company put in the ground, rather than the net value that the Company expects will result once it's reimbursed from those insurers associated with, for example, the damage that has

a police report tied to it. Is that accurate?
A (Menard) Yes. So, in Exhibit 62, on Line 38, in Column G, that $2.6 million is plant additions. And, so, as I just explained, the reimbursement does not go to offset the plant addition itself. But, if you were to look further down in Exhibit 62, on Bates -- red Bates Page 041, Line 2, there is a line called "Accumulated Provision for Depreciation". And, so, that is an amount that offsets plant in service, and the credit for the reimbursement shows up in that number.
Q And that credit for -- go ahead. I'm sorry.
A (Menard) It's not itemized on a project-by-project basis. But, in aggregate, that's where it is.
Q And that credit for reimbursements, does that typically occur six months within the amount of time that the project has been booked to plant, within that same step year, or is there sometimes a lag, where maybe the reimbursable is not collected for a period of 16 months or two years, or something along those lines?
A (Menard) So, the reimbursement collection, is that what you're asking about?

Q Yes.
A (Menard) Okay. So, the reimbursement collection can occur over a period of time. I can't say, on average, what the amount of time. But, yes, there could be lags. Like I said, we could set up payment plans with the damagers. There could be disputes with the damagers. So, there are -- there is definitely a lag period. But, you know, that is not a part of this step adjustment, because that's handled through a collections process, and would eventually impact the uncollectible expense.
What we're talking about in this step adjustment and the revenue requirement is the credit that is offset to the work orders when the damage happens. And, for that, there could be a time lag. You know, there was -- there's a time lag between when the police report is filed to when we receive that information. So, it could be -- there could be definitely a time lag.
And, so, these projects, as we talked about, they're annual projects in there, the same projects from year to year. And, so, charges will flow in from year to year. And, when we're

talking about the step adjustment and the revenue requirement, it's just the chalk line is snapped within that calendar year. So, there could be damage claim reimbursements from, you know, last year that show up to offset the revenue requirement in this year. And, you know, that could happen in each year.

So, there's -- I just want to be clear that there's a distinction as to the amount that's credited to the work order, and would show up in accumulated depreciation, versus the amount collected from the damager through the collections process.

So, if you think about it, you know, just to have a concrete example, if there was damage for $1,000 for a work order, that work order is credited for $1,000. We may only collect $500, $800, you know, whatever it is. But the work order itself, and what appears in this step adjustment, is the full $1,000 credit, and it would flow through that accumulated depreciation.

Q Okay. That's helpful. And I notice that the $2.6 million figure appears larger than initially planned. And, in the Exhibit 64, Bates 057, I think it says, that's the Supplemental Request Form for that line item, it says that those costs are -- or, that variance is a result of the "COVID pandemic" and "internal processes that were slowed and coupled with police department delays".

Can you just expand upon that for me a little bit, why there would be police department delays in returning reports related to damaged property that are attributable to COVID?

A (Menard) I would imagine it's related to staffing issues. And we've seen this not just in a pandemic year, but in prior years. Like I said, we rely on the police departments to provide the written police report, and that takes -- that can take time. There was a couple of years back where there was some -- some question as to whether police reports could be provided to external parties. And, so, there was several months where we weren't even able to get any police reports. And, so, we're sort of at the mercy of being able to obtain this information to be able to bill the damager or the insurance companies. So, if the police departments are delayed, you know, from an administrative perspective, then we don't get those police reports.

Q But, even if you don't get the police reports, a credit still appears, based on the amount in the work order, for the reimbursable, within the accumulated depreciation account in the same year that the capital cost appears on the step capital side of the ledger. Is that -- that's correct?

A (Menard) No. That's not correct. We can only apply a credit when we issue a bill to somebody. So, if we don't have a bill to issue, then we cannot credit the work order. So, if --

A (Lajoie) Or if we can't issue a bill.

A (Menard) Yes. And, therefore, there is no credit applied to the work order. So, if somebody hits a pole, and there is no police report, we do not know who to bill that damage to, therefore, the work order does not receive that credit.

Q And, just to clarify, I guess I should have been a little more clear, my question was, if there is a police -- somebody did hit a pole, but there's just sort of a lag in either the -- if somebody hits a pole, and there's a police report, but you haven't gotten ahold of the police report yet, does that still get credited to accumulated depreciation in the same year that the items are credited or appear as a capital cost on the other side of the ledger?

A (Menard) No. The credit only appears when we issue a bill. So, if we are delayed in getting a police report, if we're delayed in issuing a bill, the work order does not receive that credit until we issue the bill.

MR. BUCKLEY: Okay. That's helpful. All right. No further questions from the DOE's Regulatory Support Division for cross-examination.

CHAIRWOMAN MARTIN: Thank you, Mr. Buckley. Commissioner Goldner.

COMMISSIONER GOLDNER: Shall we take a break for lunch and return in 30 or 45 minutes?

CHAIRWOMAN MARTIN: Let's go off the record for a minute please.

[Brief off-the-record discussion ensued.]

CHAIRWOMAN MARTIN: Okay. I think

we're going to hold off on taking a lunch break, in the hopes -- and in recognition of how this was scheduled. But we will take a five-minute break right now until about 12:05. Off the record and a brief recess.

(Recess taken at 11:58 a.m. and the hearing resumed at 12:11 p.m.)

CHAIRWOMAN MARTIN: Okay. Let's go back on the record. Commissioner Goldner, go ahead.

COMMISSIONER GOLDNER: Yes. Thank you.

BY COMMISSIONER GOLDNER:

Q I'd like to go back to the Welch Island case, and ask a few questions on that. So, a question for the panel.

In the documents we have today, in the exhibits we have before us, is there any place that I can reference on a study done on what the alternatives were to the cables that were laid?

A (Lajoie) No. There's no reference to that in the documentation.

Q Okay. Was there a study done on the alternatives that we could follow up on? Or, would that be -- or, would that be something that Eversource would have to do fresh?

A (Lajoie) That would be something that would have to be done. The decision that the alternatives were not viable is just based on experience from past projects that the Company has had or proposed. We had proposed a large battery storage project, that we've since withdrawn the proposal for. And it was quite a while ago, I don't remember the exact year, we installed a large diesel-fired generator in the Weare area, to relieve a summer peak load condition. So, we have experience with large stationary generating units. And, of course, we do have a number of small portable generators that the Company owns and deploys in the event of some outages, so familiar with that as well.

So, based on the cumulative experience of these events was where the decision was made that the alternatives were not viable.

Q Okay. And it's -- the reason it's a little baffling is that I think the total expense was somewhere between 1.6 and 1.9 million, depending on which number you were using, about 100 people. So, we're talking about, you know, let's call it

18K or 19K per customer.

And the Commission is familiar with some solar pilots, for example, with large batteries, with large arrays, and those are running, I think, 20K each. So, it would have been a similar cost, I think, to this. But, you know, even with a large solar installation, with battery storage. So, we're just trying to understand -- understand those alternatives and what those look like.

Can you maybe touch on your experience with, you know, a solar installation of this size, and then a diesel installation? And I understand that diesel engines are noisy and so forth. But maybe just touch on what an expected cost would be for those two possibilities?

A (Lajoie) I'd have to go back and look at the information we have from the diesel installation that we did. Like I said, it was a number of years ago.

The Company, in New Hampshire, has not installed large solar arrays, company-owned. My understanding is that we're prohibited from owning generation at this point, although I may be mistaken on that point. The divestiture of generation did limit our ability to own generation in the state. So, we'd have to go back and look at, you know, what we've done in other states, and what private companies have done, and so forth.

Recall, however, that this is an island with limited real estate. We have a right-of-way for a line to run on the back lots of the properties. Obviously, the residents of the island own all the land with shorefront exposure, and those lots go back toward the center of the island. So, real estate, to locate such a device, would, of course, be at a premium, and island property is not cheap.

Q Do you have -- you mentioned, I think earlier, the panel mentioned earlier, environmental concerns. Was there a study done on the environmental concerns or is there any documentation on those concerns?

A (Lajoie) There was no study done, or nor is there any documentation on those concerns. Again, the discussion was based on our experience with the diesel generator, and just the general issue of transporting fuel by boat. We have installed generators on islands on a temporary basis. But, for something as large as what we're talking about here, we've never done anything on that scale, and just had general concerns with that possibility.

As I mentioned, the diesel generator that we did install, there were air quality permits required that had to be renewed. I wasn't directly involved in that project. But a good friend of mine at the Company was, and was able to relay his experience on that. He was actually part of the committee reviewing these projects. So, he was able to relay his experience verbally to the group, when we were talking about whether or not to approve this project.

Q Okay. And you mentioned, I think, before, the panel did, that there was some open question on whether customers on the island could have benefited in the transaction via easements. I think you mentioned before that there was no information on that available?

A (Lajoie) I did research that. I can go back and verify with our Real Estate group, because they do file all easements that are -- that are obtained. And, you know, obviously, they're filed with the local Deed -- Registry of Deeds. So, I can go back and look at all that information.

I was looking through the project documentation, and couldn't find anything that indicated easements had been purchased from the island people. And my recollection of discussing the project with the person who was managing the project, were that -- or, my recollection is that we were able to get agreement from the landowner on the island for the cable termination, as long as it ended in the same spot, and was actually placed a little bit further from shore, without having to purchase an easement.

But, if you would like, we certainly can go back and check into all easements that we have on the island?

Q Yes. Thank you. I mean, I think the challenge is that, you know, we have a project that was originally estimated at 360K, ended up being, you know, something closer to 2 million. And, from, you know, a prudency perspective, we're just trying to gather the information.

And, so, maybe what we can do, as I look at the various pieces of information, is to -- is to make a record request to understand what the diesel cost would have been, because I think that looks viable.

Solar, I was thinking actually of rooftop solar. I mean, you could basically have had rooftop solar on every house, with a battery, for roughly the same cost, though that doesn't improve the picture. It makes it sort of a parallel. But give the Company an opportunity to talk about what the alternatives would have been, any comments that you'd like to make on environmental concerns.

And then, to your point, too, I think, balance that out with, you know, did any customers benefit via easements, and to sort of bundle that all into a record request, to give the Company an opportunity to put their case forward.

Does that make sense? Anything, any comments on that request? Or questions?

A (Lajoie) The request for the cost of a diesel installation, I mean, 24/7/365, maintaining a diesel plant on an island, it would most likely be a pretty significant estimate as to what that would cost. And, you know, these are homes that are inhabited year-round. So, --
Q Yes. That might work -- that might work in your favor. But, yes, just, you know, from a Commission standpoint, we're looking at, you know, a project that was estimated at 360, it cost a lot more. So, from a prudency perspective, I'm just trying to give the Company an opportunity to put forward the facts, to understand why, you know, the nearly $2 million is reasonable. That's all. So, --
A (Lajoie) We will certainly comply and provide that record request, yes.
Q Thank you. All right. So, that's all the questions that I have on Welch Island.

If I move to I'm going to call it the "Pemi" case, if the design -- where I want to go on this is that, you know, when we look at how utilities are paid, in terms of cost of capital, return on equity, return on debt, return on debt is grounded in, you know, risk-free returns, and return on equity means that those projects have some risk associated with them, and things sometimes don't turn out the way that you planned.

And I, myself, am a former design engineer, so I can appreciate that things sometimes and often do go wrong. So, I fully appreciate, I think, the situation in things don't go always as smoothly as you want.

And what I want to go to on this is, if the design was done correctly, if it was done right the first time, if everything would have fallen into place, is that the $4 million number that we were looking at before? Is that approximately correct? I noted that there was an error in the indirect costs. So, I think that would probably need to be adjusted. But, outside of the indirect adjustment, is that correct?

A (Plante) No, not exactly. The correct number for if all things went well, without any errors, would have been the -- on Bates 026, Row 19, that's the -- oh, my God, my eyes are killing me here, the 6.8 number.

Q I'm sorry, the which number?
A (Plante) The 6.8, which was in the First Supplemental Funding Request that we did not fully approve, because that --
Q Okay. Can you -- I'm sorry. If you wouldn't mind orienting me on the exhibit and the page number please?
A (Plante) Oh, boy. Let me try.
Q No, take your time. It's just important to get the documentation right here.
A (Plante) So, on Exhibit 62, Bates 026, I'm not quite there yet either. Bates 26, Row 19, or Line 19, in Column A-u -- oh, my God. I'm looking at it sideways, but the line is in landscape view here -- Column J, there's a number there of 6.8 something or other. And that is the value of the initial, I hate using a word like "initial", the First Supplemental Request Form that was submitted and approved in June of 2020 through EPAC, but not fully approved in PowerPlan. So that one proposed to take the authorized amount from 4.1 million to 6.8 million. And, so, that was an increment of 2.7. And, of that, the lion's share was overheads.

So, there was 800,000 of direct costs increase, and, you know, 1.9 of indirect costs, so overheads and AFUDC. So, that 800,000 increase in direct costs was by and large the control house expansion that we talked about earlier today, and along with a little bit of costs for the animal protection equipment that was installed and, you know, little things, but it was mostly the control house expansion.

So, that would have brought the total request to 6.8. And, as I mentioned earlier, had we been following our current authorization process, we would have incorporated that 6.8 number in our full funding request, because we would have already known about the control building expansion needs, we already would have known about the animal protection, we already would have known about the total overheads, and the fact that we also delayed the in-service date by a little over a year, which compounds the AFUDC.

Q Okay. Thank you. And how does that 6.8 million compare to the final -- the final bill? Was it 7.9 or something? I'm not sure I have that handy here.

A (Plante) 7.7.

Q 7.7?

A (Plante) Yes.

Q Okay. That's the 900,000. Okay.

A (Plante) Yeah.

Q Okay. Thank you. All right. And the only other question I have on this one was, could someone maybe just give a high-level overview of what exactly caused the phasing error?

A (Plante) I can try. I don't -- I wasn't on-site. I'm not a testing and commissioning expert by any means.

But, during the test energization process to energize the transformer, there were probably sixty-ish or so switching steps that are involved with doing that. Each step would have some involvement of the testing team, to validate that the thing that they're expecting to see for, you know, voltages in various areas are as expected.

And, at some point, when we were validating voltages at the Synch Scope, they detected that they were not getting what they should have been getting. And that gave them enough information to say "We can't go forward, because we have an error somewhere."

And I lost Commissioner Goldner.

CHAIRWOMAN MARTIN: We actually lost you by video again, Mr. Plante.

WITNESS PLANTE: Eh. I'm sorry.

CHAIRWOMAN MARTIN: Hold off for a minute, maybe you will reappear.

WITNESS PLANTE: I hope, but can't guarantee.

CHAIRWOMAN MARTIN: Let's go off the record for a moment until we see if it does.

(Off the record discussion ensued.)

CHAIRWOMAN MARTIN: Let's take a five-minute recess while he does that and come back. I don't expect that it will take more than an hour on questioning.

Okay? Come back about 12:40 to restart. Thank you.

(Recess taken at 12:33 p.m. and the hearing resumed at 12:43 p.m.)

CHAIRWOMAN MARTIN: Okay. Let's go back on the record. Commissioner Goldner.

BY COMMISSIONER GOLDNER:

Q Yes. We were just -- Mr. Plante and I were just trying to sort out this phasing error. And maybe, Mr. Plante, I could maybe put it a little bit differently. And, if you don't know the answer to that, that's okay. We can make it a record request.

But what I was really trying to get at was, the root cause of the phasing error, was there, you know, usually companies go through a root cause analysis and sort out what happened, and, you know, have kind of a written report, "Hey, we spent the next million or two or three million dollars, because this happened or that happened."

Was there a root cause analysis done on this? And I'm specifically interested in, you know, was it a hardware issue? Was it a software issue? That's kind of where I'm going.

A (Plante) So, we did not perform a specific root cause type of analysis here. We certainly did evaluate where the error was in the engineering. So that, I mean, if you were to look for a root cause, I think everybody can pretty much agree that there is an engineering shortcoming here that we discovered during the testing process.

But, no, we did not perform a detailed root cause analysis. We don't feel that there was a hardware or software issue that caused or contributed to this issue.

Q Okay. So, I'm just trying to make sure I interpret it right. It's really -- you would characterize this as a "design" issue?

A (Plante) Yes.

COMMISSIONER GOLDNER: Okay. Okay. That's all I was trying to get at. Okay. Very good. Thank you, Mr. Plante.

And my last, maybe, you know, question or comment is really directed at Mr. Buckley, who I know is not a witness. But, Mr. Buckley, will you be addressing in your closing the sort of eight or nine year gap on this taps issue, between when Eversource stopped doing it one way, and the Audit Report that highlights that that's a concern or an issue? Is that something you will be able to address in your closing?

MR. BUCKLEY: Yes, absolutely, Commissioner Goldner. I will address that in my closing.

COMMISSIONER GOLDNER: Thank you. Thank you, sir. Okay. That's all I have, Chairwoman.

CHAIRWOMAN MARTIN: Okay. Thank you.

BY CHAIRWOMAN MARTIN:

Q A quick question on one of the specific projects, on, I believe, red Bates 027, Line 55, of Exhibit 62. There's one project called "Emerging Capital Security". If someone could just describe that project and what it entails for me please?

A (Menard) Would you be able to repeat the Bates Page number?

Q I believe it was Bates 027. Let me go back and double check. It's the second page. And it is Exhibit 62.

A (Menard) Yes. I see that. Line 55?

Q Line 55.

A (Menard) Unfortunately, I don't have the detail behind this. It is a project related to information technology. I don't have the detail handy, but we could certainly follow up.

Q Okay. If no other witness does, then I think that would be a record request for the Company.

A (Menard) And are you looking for a general description of what the project is?

Q Yes. It's not -- it's not very clear from this what it involves.

(Short pause.)

BY CHAIRWOMAN MARTIN:

Q Okay. Thank you. We heard some testimony earlier today from Mr. Lajoie about the process for approval, and Mr. Kreis raised the issue related to some testimony about projects being authorized "any time of the year". And Mr. Lajoie had explained that a lot of times there are later projects involving emergency replacement or unforeseen circumstances. I'm wondering, Mr. Lajoie, if there are any of those in this step increase request? And, if so, can you point us to the justification form for those that is in the exhibit? And, if not, can you provide that to us as a record request?

A (Lajoie) Yes. We can certainly provide that. I'm just quickly scanning through, and I don't see anything that's an emergency replacement here. But, rather than depending on my ability to read quickly, we will do that through an information request.

CHAIRWOMAN MARTIN: Okay. And I apologize for the delay, I just keep track of what we have for record requests. So, that would be identifying those and providing any related justification form, as you described?

WITNESS LAJOIE: Yes.

BY CHAIRWOMAN MARTIN:

Q Okay. Going back to the submarine cable project, with the $360,000 initial estimate. Given the significant disparity, I am wondering what vetting is done, and maybe this has changed, we heard Mr. Plante reference a change in process, but does the EPAC look to determine whether it's a reasonable estimate? And a second question on that is who is on the EPAC? What are their qualifications?

A (Lajoie) Because this was a distribution line project, and it was reviewed by the New Hampshire PAC, which is a local New Hampshire group, as opposed to the EPAC, which is a tristate group. The EPAC looks at substation and transmission projects. Distribution line projects are reviewed within the -- within the individual state Project Authorization Committees, PACs.

We can certainly provide you a list of the members who are on the New Hampshire PAC committee.

Q I think I'm less interested in their specific identify as to -- and more as to how their qualifications are determined. And, fundamentally, it's a bit surprising that there could be an estimate for $360,000 that would be approved in the scenario we're hearing, where the scope really doesn't change, and this involves submarine cables to an island.

A (Lajoie) So, the members of the committee, and it's composed of managers and directors of various groups within the Company; Substation Operations, Field Operations, System Planning. I'm kind of the Chairman of the committee. Field Engineering is another group that the director is a member of the committee. We have a manager from Planning and Scheduling, and so forth.

So, you know, it's people with a wide variety of backgrounds and experiences within the Company who are reviewing the projects, and determining whether the project is justified or not.

And then, your next question was, I'm sorry?

Q That's fine. So, you're the perfect person for this question. Can you describe the process, if there is an estimate that the PAC would think was unreasonably low, how would that be addressed?

A (Lajoie) In general, when people come in with projects, we review the documentation. We're looking for things like "what is this estimate based on?" This one that we're talking about was from 2016, and prior to my direct involvement at that, you know, in 2016. We're looking for, you know, "How was this estimate derived?" "What is it based on?"

And, over time, I can tell you the committee has gotten of -- better at pushing back and making sure that it is, in fact, based on a bid, you know, that we can put our hands on. That it's based on something that's been designed within our work management system. We've had changes to the work management system over the years, and have had some problems where the estimating function wasn't working very well, but at the moment it is. Those tend to be the more normal work for us, you know, building a pole line or building an underground line. Submarine cables, since, as I mentioned, I think, it really is nothing that we do on a regular basis, would be one of those items that should be sent out to bid.

The original form, as we discussed I think earlier, didn't have a basis for the cost estimate of 360,000. Looking back on it now, I would hope that we would stand up and say that "this doesn't really look right, it looks pretty low."

But, again, without having had any experience with submarine cable in the recent past, the last one that I was involved in was probably in the late 1980s, on Newfound Lake. Without having any recent experience on submarine cable installation, you know, I would hope that we would get -- today, I feel confident that we would have the bid in front of us, to be able to be sure that the cost is based on something that, you know, it's cast in concrete.

Q Thank you for that. We've heard a couple times that there's been a change in process. When did that occur?

A (Lajoie) There's been multiple changes in process. A lot of them have occurred as we progressed through the rate case and subsequent hearings. I think, well, perhaps some of our documentation had been lacking previously, and that was pointed out to us as part of this whole process. So, we've gotten a lot better at providing or establishing better documentation requirements as time has gone on.

Q I'll just briefly turn to Mr. Plante, because I think that you had mentioned a couple times that there is now engineering requirements related to the approvals and additional details. Was that a single change that you were referring to? Is that a series of changes since 2016?

A (Plante) I would say it's a series of changes that have been put in place over the past couple of years. Some of them are based on learnings that we've taken away from this rate case. Others are from learnings that we've taken throughout the three-state enterprise. For instance, a now formalized process for performing both substation and line constructability would be used. We had a three-state group pulled together of subject matter experts, as part of an initiative, an initiative to define the things that we should be looking at or looking for at various stages of project development, so that we can effectively progress the design and estimating those projects. It's eliminating, we're never going to eliminate everything, but minimizing the things that crop up later on in the process.

So, part of our approval requirements now are to, in addition to submitting a PAF, Project Authorization Form, we need to submit a constructability review document, which is a pretty detailed assessment, the existing conditions, and questions and check boxes that you need to evaluate. Project schedule is another requirement for the project approval through EPAC. Process of schedule never changes, but it demonstrates that your project estimate is based upon some boundaries in time, as well as some boundaries in outage claim.

So, have we thought about what we might

need for outages to complete the construction? Have we talked to our Control Center and gotten feedback from them, that, yes, they feel that we can -- we can be granted those outages, or, "no you can't", or, "yeah, you can have it in the spring, but not in the fall." You know, those types of kind of objective evaluations of, you know, whether our thoughts on how the project might unfold are, in fact, reasonable.

Q Okay. Thank you. Do you know specifically when the engineering requirement was added?

A (Plante) What we -- I don't remember exactly the date, but I would probably say, like, two years-ish ago, where we were looking to have the engineering advanced somewhere near the -- what we would call -- what we used to call the "70 percent stage", so that we could then start talking to contractors about construction costs.

CHAIRWOMAN MARTIN: Mr. Fossum, I just want to clarify for the original record request I had, it relates to the planning and this approval process. That it sounds like there is a current approval process in place, it would be helpful to understand that.

MR. FOSSUM: Understood. Yes.

CHAIRWOMAN MARTIN: Okay.

MR. FOSSUM: And I believe the documents in the LCIRP filing that we can provide would speak to both the approvals -- both of those issues, but we'll find that.

CHAIRWOMAN MARTIN: Okay. Thank you.

BY CHAIRWOMAN MARTIN:

Q Oh. We heard some testimony related to the approval in this, I believe it's the same project -- nope, it's in the Pemi project. And the EPAC, I believe, was involved in the subsequent approval of that project, is that right? Did I understand that right? I think that was Mr. Plante.

A (Plante) Yes. EPAC is the approval body for major substation projects. And that's a three-state organization, and it's chaired by the Director of Asset Management. And it's comprised pretty much of all of the directors of the -- in the areas of our Company. The various engineering directors, operations directors, community outreach directors, you know, some pretty broad spectrum of expertise.

Q I thought I understood you to testify that that approval ultimately came in April of 2021. But this project that we're being asked to approve here was placed in service in 2020. Can you help clarify that for me?

A (Plante) Yes. So, the final approval of the supplement did come through in late -- or, early 2021. And that's -- yes, as I mentioned earlier, we had a Supplemental Funding Request that was routing for approval, but we stopped in the fall when we discovered we had this problem with the Synch Scope. And, at that point, we began gathering the additional information that was required to, you know, get a good understanding of what the, you know, the total impact of that event was. And it just took a little bit of time to gather all that stuff. And I think it was early -- looks like mid January that we were able to finally get the document put together and submit it to EPAC. And then, they approved it in April, and then it went through the PowerPlan approval process subsequent to that.

Q It's my understanding that was a retroactive approval or am I misunderstanding the testimony?

A (Plante) No. You're understanding it kind of correctly.

Q Okay. Thank you. Just wanted to make sure. We also heard, related to the Pemi project, that, and heard some more through Commissioner Goldner's questions, that the vendor -- that there was an error, an engineering error, and that the vendor essentially did not charge for the engineering related to addressing that problem.

There were questions related to whether there was the ability to hold them liable to a greater extent. And part of your testimony in response was that there were contractual limitations on that, which I understood, but then also the internal engineering accountability related to that as well.

Is there any accommodation reflected in the step increase or in the cost for the project to account for the Eversource engineering -- internal engineering issues?

A (Plante) I'm not sure I understand your question.

Q I thought I understood, or I assumed from what you were saying, that there was some responsibility for the issue that fell on Eversource, related to the review and not catching that error. And, so, I'm wondering if there is some accommodation for that reflected in the numbers before us?

A (Plante) Okay. So, yes. Our internal engineering folks were involved with the reviews and whatnot, the various design deliverables. And I guess, in terms of "accommodation", you're asking did we include the total cost of the internal engineering, that involvement, after that event was discovered?

Q Yes.

A (Plante) And my answer is "No." We have included all of the costs that our engineering folks have incurred for most of the project in this, in this filing. I think that's correct. Right, Erica?

Q Okay. Thank you. I have a question for Ms. Menard related to the change in the policy in 2012. You noted that you had changed the accounting policy of the Company in 2012. I'm wondering if that was based upon a change in the language of the FERC rule or whether that was just a change in the policy internally, not based

upon any change in the rule?
A (Menard) If I'm recalling correctly, I believe it was around the time of the merger between NSTAR and Northeast Utilities. That there was a review of policies between the companies. And I believe it was made at that time.
Q Okay. So, you're not aware of any change in the language by FERC?
A (Menard) I'm not aware of any.
Q Okay. Thank you. Probably also a question for Ms. Menard.
The Audit Report that we have as an exhibit today said that "the Company has not responded sufficiently", and that was dated "February 1, 2021". Has the Company provided a further response to the Audit Division?
A (Menard) Could you direct me to which audit issue?
Q Let me see if I can find the page. Okay. I think I have it. It is Exhibit 63, at Bates Page 003, Audit Issue Number 1. It said "To date, the Company has not responded sufficiently."
Since that date, has the Company provided a further response?

A (Menard) I believe the Company has provided the response. And it's hard to tell from that sentence whether the "to date" is referring to "February 1st" or whether it was part of the original audit, like a draft report or something.

From the Company's perspective, we believe we have provided a response.

Q Are you aware of whether the Company has provided a response since February 1st, 2021?

A (Menard) I don't believe there's been any further discussions. I was just trying to recall when our step hearing last was. Outside of -- if I could just take a second to look?

Q Go ahead. An easy way to deal with this may be that, to the extent the Company has provided a further response after February 1, 2021, or if, as you suggested, this is a remnant from a draft, a response after that draft date, if you could provide that as a record request, that might be the most simple way to handle it.

A (Menard) Yes. I'm just looking, and the last responses that we had were those Staff data Requests 17 and 18 sets.

We have had further discussions as part

of this step adjustment, where the Company has provided, in Set 19, which is Exhibit 64, there have been further -- further information provided. And those are the only items, as part of this particular issue, that have been responded to by the Company.

Q Are you aware of any -- this exhibit notes this to be the "Final Audit Report". Are you aware of any subsequent versions of this? And I'll ask the same of Mr. Buckley.

A (Menard) I am not aware of anything beyond this Final Audit Report. I don't know if the Regulatory Support Division has anything.

MR. BUCKLEY: No. I would just echo what Ms. Menard just said.

CHAIRWOMAN MARTIN: Okay. Then, Ms. Menard, I will just ask that you confirm that there is no further response related to this, and, if there is, provide it in a record request.

WITNESS MENARD: Certainly.

CHAIRWOMAN MARTIN: Thank you.

BY CHAIRWOMAN MARTIN:

Q Okay. Once last question. It's my understanding that any amount approved in this step increase would also be reconcilable based on a subsequent audit by the Department of Energy Staff. Is the Company in agreement with that?

A (Menard) Yes.

CHAIRWOMAN MARTIN: Okay. Thank you. I have no other questions.

Mr. Fossum, redirect?

WITNESS MENARD: Yes. If we could just follow up on the question that you asked, Chairwoman Martin, on that "IASC2003" project?

CHAIRWOMAN MARTIN: Okay. Go ahead.

WITNESS MENARD: We were able to find some information about that that hopefully should answer your question.

CHAIRWOMAN MARTIN: Okay.

WITNESS MENARD: Mr. Devereaux can respond to that.

WITNESS DEVEREAUX: Thank you, Erica. Yes. It's security equipment used in our work centers for the 2020 year. There was a camera added in the Derry Work Center, the Hooksett Work Center, Rochester Energy Park, and Chocorua, along with a satellite phone for Energy Park in Manchester. These are all for security purposes.

CHAIRWOMAN MARTIN: Okay. Thank you for that.

WITNESS DEVEREAUX: You're welcome.

CHAIRWOMAN MARTIN: All right. Mr. Fossum.

MR. FOSSUM: Just before I -- I think I only have a couple of questions. But, before I do that, you had left us with a record request on this "Emerging Capital Security". And I believe that's what Mr. Devereaux was just explaining.

Do you still want a record request response or was that sufficient?

CHAIRWOMAN MARTIN: That was sufficient. Thank you.

MR. FOSSUM: Thank you.

BY MR. FOSSUM:

Q And, in the hope of potentially addressing another record request, Ms. Menard, could you please look at Exhibit 63, Page 15?

A (Menard) Yes. I'm there.

Q In the middle of that page, do you see the sentence "To date, the Company has not responded sufficiently", under the bolded heading "Issue"?

A (Menard) Yes. Yes, I do.

Q Is the information that follows after that the Company response that begins at the bottom of Page 15 and continues on? Is that additional information that was provided subsequent to that issue being identified?

A (Menard) Yes. That is my understanding.

Q So, would it be correct to say that that identification of information that "was not sufficient" was then filled in with additional responsive information that was included in the audit?

A (Menard) Yes. That is -- that would be my assertion. I cannot state, from the Audit perspective, though, if that relieves their issue related to the "To date, the Company has not responded sufficiently."

From our perspective, that is our response. And that response that you identified, coupled with some attachments at the end of the Audit Report, are responses to that issue. And, so, we believe we responded sufficiently. But there has been no further discussions with Audit or the Department of Energy Staff on the topic.

And, if I recall from the last step

adjustment hearing, there was some discussion on the topic. If I were to go to the transcript, I think we talked about, you know, the issue being discussed in more detail during the business audit process review.

Q So, my understanding, just to wrap this up, my understanding from what you're saying, that some responsive information was given, a report was issued, and it was your expectation there would be some additional discussion or deliberation on the various issues, and that has not happened?

A (Menard) That's correct.

MR. FOSSUM: I think that was all that I wanted to clear up. Thank you.

CHAIRWOMAN MARTIN: Mr. Fossum, I'll keep that record request in place, because I would appreciate it if the Company would confirm that there have been no additional responses since the report came out. But, to the extent there aren't any, you just don't need to file them. I understand the clarification you just made. Okay?

MR. FOSSUM: Understood. So, then my understanding -- so then that response or that request remains to confirm whether there have been additional information. And, so, if there has not, we will provide a response that says that there has not.

CHAIRWOMAN MARTIN: Okay. Thank you. Do you have any further redirect?

MR. FOSSUM: No.

CHAIRWOMAN MARTIN: Okay. Then, we will -- we have already admitted Exhibit 63 and 64 as full exhibits. Is there any objection to admission of Exhibit 62?

(Atty. Buckley indicating in the negative.)

CHAIRWOMAN MARTIN: Okay. Seeing none. We will strike ID on 62 and admit that as a full exhibit as well.

And we are holding the record open for Exhibit 65, regarding the planning and approval process; Exhibit 66, regarding alternatives on the submarine cable project; Exhibit 67, regarding emergency or unforeseen project approvals and related justification forms; and Exhibit 68, regarding any additional responses by the Company to the Audit Report.

Anything that I'm missing there? Any questions?

[No verbal response.]

CHAIRWOMAN MARTIN: Okay. Seeing none. Anything else from you, Commissioner Goldner?

COMMISSIONER GOLDNER: No.

CHAIRWOMAN MARTIN: Okay. Then, we'll take closing statements. And, Mr. Plante, you may be excused.

All right. Starting with Mr. Kreis.

WITNESS PLANTE: Thank you very much, Chairwoman.

CHAIRWOMAN MARTIN: You're welcome. Enjoy your time.

WITNESS PLANTE: Thank you.

MR. KREIS: Thank you, Chairwoman Martin.

On behalf of the OCA, I wanted to thank everybody for a very interesting and informative hearing. And I want to confess that this hearing as brought me up short, in the sense that the OCA does not have the expertise to conduct the kind of thorough review of the prudence of the Company's capital expenditures, either this

Company or any other company. And we have historically relied on what used to be the Staff of the PUC, and what is now the Department of Energy, for their thorough analysis, and also the analysis that the Audit Division, of what is now the DOE, also conducts.

With respect to the last colloquy, between Chairwoman Martin and the Company referencing Exhibit 63, looking at Page 18 of that exhibit, it appears to me that the Audit Division of the PUC did not back down from its concerns. And, so, therefore, I think the PUC should not back down from the concerns that both the DOE and the Commissioners from the Bench have expressed here.

I thought that all of the discussion of the Welch Island cable project was very interesting. And I'm glad to see that the Commission has left that issue open, in the sense of having interposed at least one record request, to try to figure out more about how that particular scenario went down. And I guess the same is true of the Pemigewasset Substation.

Just as a general process concern, I

start to get itchy, I guess, when there are so many important record requests that are left open at the end of a hearing, that I would imagine that there is a point at which the hearing record becomes so incomplete at the end of a hearing that the Commission should consider whether to reconvene the hearing, so that the responses to the record requests can be put in their proper context.

I will look at whatever the Company circulates by way of responses, as I'm sure the DOE and the Commission will. And, I guess, at this point, I want to reserve the right to file a request that the Commission convene another hearing here.

Obviously, the Step 2 increase is part of the Settlement Agreement in the rate case, that I signed, and that the Commission approved. And I don't want to become an unhelpful impediment to that step increase being implemented on a timely basis. But I think there's a lot of unresolved -- there are several significant unresolved issues here, as this hearing has demonstrated. And, for that reason, I am not going to take a position at this time about whether the Commission should approve the Company's filing.

And I note that it really is -- it is overall the burden of the Company to demonstrate the prudence of all of the expenditures that it seeks recovery of through this, or any other rate. And I'm not sure what -- I'm not sure what to ask the Commission to do here. So, ultimately, I take no position, at least not at this time.

Thank you. I think that's all I have to say.

CHAIRWOMAN MARTIN: Thank you, Mr. Kreis. And I think you raise an important point that we need to cover, following up on your "leaving the record open", timing on the record requests. Given the timing related to this matter itself, when can the Company provide those responses?

MR. FOSSUM: I'm not sure. I believe the first one can be done very, very quickly, as likely can the last.

The two middle requests I'm less

certain of. I guess the big concern, from my perspective, is the second request, now held for Exhibit 66, is requesting a new analysis. I suppose I would look to somebody like, and I don't mean to put you on the spot, Lee, I don't know how quickly you could pull that together?

WITNESS LAJOIE: I'm not sure. I think it depends, in large part, on the amount of detail we go to. But, if you're willing to accept estimates, you know, we can certainly get it done a lot faster. But, if I'm going to do it, it's going to be within two weeks.

MR. FOSSUM: I mean, I think -- I understand that this is sort of a hypothetical or, you know, an analysis of what things would have been, so I'm quite certain there will be some measure of estimation involved.

CHAIRWOMAN MARTIN: Mr. Fossum, for the three, other than, let's see, we've got Exhibit 66, which is the alternatives analysis, do you expect that those could be submitted by, say, Thursday of this week? I know that's a short turnaround. But I would think that even Exhibit 67, regarding the emergency or unforeseen approvals, that's information you have in your system, and you should be able to pull that together pretty quickly.

MR. FOSSUM: I don't disagree with that. It would be a matter of just identifying them, and then doing that. So, I don't imagine that would take a very long time to do.

So, for those three, subject to somebody correcting me, I wouldn't see an issue of getting them in by Thursday.

CHAIRWOMAN MARTIN: Okay. Let's say Thursday. If you have an issue with the one, please file something letting us know.

Just a minute. I'm going to go off the record for one moment.

(Chairwoman Martin conferring with Commissioner Goldner.)

CHAIRWOMAN MARTIN: Let's set the deadline for the other one for next Tuesday, the 20th. And, if the Company is not able to meet that deadline, if you can file something as soon as possible letting us know.

MR. FOSSUM: Understood.

CHAIRWOMAN MARTIN: Thank you. And,

before we move on to Mr. Buckley -- oh.

MR. FOSSUM: Before that, you said, wait, I just now wrote down, --

WITNESS LAJOIE: For clarification --

MR. FOSSUM: -- you said "Tuesday, the 20th". Did you mean "Tuesday, the 27th"?

CHAIRWOMAN MARTIN: I did. Thank you very much for clarifying.

Okay. And, Mr. Kreis, I also wanted to respond to your concern about when there are significant record requests, and the record is left open. And I a hundred percent agree with that concern, and share it at times.

And, so, to the extent there is a desire by any party to be heard on anything that does come in, please do plan to file something and let us know that.

MR. KREIS: I appreciate that, Madam Chairwoman.

CHAIRWOMAN MARTIN: Okay. Thank you. And on to Mr. Buckley.

MR. BUCKLEY: Thank you very much, Madam Chair.

Teeing off the timing considerations

that the Consumer Advocate brought up, it occurs to me that, at least sort of administrative matterwise, if I were still at the PUC -- representing PUC Staff, I might ask for a rushed transcript for this proceeding. But that is no longer my role. I'm not going to do that. But I'll just maybe note that for the folks in the room.

So, in closing, the Department of Energy's Regulatory Support Division has conducted an extensive and detailed review of the accuracy of the proposed rates as filed and the projects the Company has requested for recovery in the instant proceeding. We continue to have concerns about project cost overruns that occur between the planning stage and when a project is closed to plant, but look forward to reviewing the recommendations of the business process audit for how such cost overruns could be avoided and initial project planning might more accurately reflect actual project costs.

In the case of the Pemigewasset Substation, the Regulatory Support Division recommends the Commission direct the Company to remove at least the $911,000 cited at Exhibit 64, Bates 056, the amount the Company witness identified as "consequential damages" relating to the error of its third party consultant. Ratepayers should not be on the hook for incremental costs associated with the errors of a third party consultant.

Furthermore, in light of the Audit Division recommendations, we also continue to have concerns about the accounting treatment of the load tap changer controllers, which we think inaccurately accounts for their maintenance as a capital addition, rather than simply an expense. And would recommend that the Commission direct the Company to remove, from this year's step, and at least last year's step, that which the Company has agreed would be subject to reconciliation, based on the Audit's recommendations.

As expressed by the Company witness, the replacement is clearly done during the maintenance of a larger apparatus, with a longer average service life, similar to the replacement of a faulty distributor cap on my car.

We also continue to have concerns over

the Company's treatment of damaged property, and encourage the Commission to take a hard look at this issue. The Audit Division recommendations, and the diminished incentive the Company would have to collect police reports in a timely manner, if it were to continue to book gross plant associated with these accounts credited for depreciation, rather than booking net plant, consistent with the Audit Staff's recommendation, as it considers the Company's request.

Having said all of that, in summary, the Regulatory Support Division views the projects requested for recovery in this step as used and useful, their costs as prudently incurred, the rates proposed as just and reasonable, and recommends their approval by the Commission, subject to subsequent audit, but also subject to the following caveats: As far as the Pemigewasset Substation, we recommend non-recovery of the Company characterized -- of what the Company characterized as the incremental costs of $911,000. As far as the LTCs, we recommend the Commission direct, on a going forward basis, reversal of the Company's 2012 decision on treatment of LTCs, recommend the Commission direct their removal from this step, and recommend that rates be reconciled to reflect a removal of LTCs from at least the last step, consistent with the Audit's recommendation, and the Company's agreement during the last step hearing. And, finally, we ask that the Commission act on findings -- on the findings on the expertise and on the recommendations of the Audit Division's report, related to accounting for damaged property, rule on the matter within this step increase, and reconcile treatment of the issue during last year's step increase.

Thank you.

CHAIRWOMAN MARTIN: Thank you, Mr. Buckley. And Mr. Fossum.

MR. FOSSUM: Thank you. I'll start, as I often do, sort of general, and I'll get more specific.

In general, the Company does support its filing as made, and believes that the projects that are identified were reasonable and appropriate projects that were prudently managed, that the costs were prudently incurred, and should be recovered fully, and that the rates calculated consistent with them are just and reasonable and should be approved as filed.

With respect to a few of the specific issues, and one of the things I guess I'll speak to is is an issue that has come about, the timing and the need for some additional information. As Ms. Menard had indicated in her testimony, some of the items in the Audit Report, they were known, you know, many months ago, and were to be subject to further discussions that she has testified haven't happened, but we'll confirm that by the record request, but that is the testimony that you've heard. So, and our understanding, therefore, was that some of these issues were to be discussed further, and handled in a different way, and not borne out in the relatively tight timeline of a proceeding like this.

Getting to some of the more specific issues, the Department of Energy Staff has just recommended removal of costs associated with the Pemigewasset Substation project. And, as you heard Mr. Plante testify today, those $911,000 that were identified came about because testing did exactly what it was that testing was supposed to do. It revealed an issue that needed to be addressed before an incredibly expensive piece of equipment, serving many customers, went into service and potentially resulted in some kind of a catastrophic failure. The cost that came from that were not inherently unreasonable. They were the byproduct of a proper process working properly.

The fact that the Company is unable to recover all of the costs of that from a third party is not an indication that those costs were imprudent or unreasonable. And we would put forth that the project should be approved as it has been filed.

With respect to the load tap controllers issue noted in the audit, those, as Ms. Menard testified to, those load tap controllers have been capitalized now for many years, including at the time of the rate case that was just completed. Meaning that those were capital items at that time and factored into the Company's revenue requirement as such at that time. To change their handling afterward, when they have been handled in a particular way for nearly a decade, and through the Audit Staff's review in a rate case, seems unreasonable and inappropriate.

There may be room for reasonable disagreement about the meaning of a FERC regulation. And, clearly, that disagreement exists. It would be our position that this is a continuing disagreement that has yet to be resolved, and is not a basis to call for the removal of a number of cost items that have been appropriately included.

On the issue of insurance recoveries, the Department of Energy Staff's position seems to assume that recovery of costs from damage causers is a given. And that only the net plant should be involved, because at some level the dollars will be recovered. And, as you've heard Ms. Menard testify, that isn't the case. There is no diminished incentive on our part to recover those dollars.

When damage is done to our system, that doesn't create a blank check for us to build whatever we like and whenever we like, regardless of the cost or its utility. We replace the equipment that's damaged, credit the work orders appropriately, and we account for the cost as Ms. Menard has testified. Nothing about any of that treatment is inappropriate or unreasonable. And, again, to the extent that there may be some further discussion to be had about it, we would welcome such further discussions, but don't believe it is appropriate, on the evidence that you have before you, to conclude that it's being inherently handled improperly. If there is a disagreement, I think there's room for us to talk about it.

Also, as the DOE Staff noted, the business process audit would likely reveal some information about the way that the Company conducts its business, hopefully all positive, but likely that there are areas for improvement. And we are open to that improvement.

You have heard both Mr. Lajoie and Mr. Plante testify today about changes that the Company has made in last few years to improve its processes, to make its estimates more rigorously evaluated, and to make sure that we're working with the fullest and most complete information possible, and that we are controlling the cost and scope and other issues on every project that we come across. We are open to making more changes as might be necessary.

So, with that said, I believe it's fair to say that, on the evidence that you have before you, that the testimony you have heard and the information that's been presented, there is no evidence that indicates that these projects were improper or imprudent, and the cost of them should be recovered, the rates as calculated and shown in the testimony should be approved as filed, and we request that the Commission do so.

With that said, we will look to provide the record requests as quickly as we can, and give the Commission a complete record upon which to make its decision. Thank you.

CHAIRWOMAN MARTIN: Okay. Thank you, everyone.

With that, we will close the record, other than for the record requests that we left open, and adjourn this hearing. Have a good rest of the day.

(Whereupon the hearing was adjourned at 1:40 p.m.)

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DE 19-057

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
D/B/A EVERSOURCE ENERGY

Petition for Permanent Rates

Order Following Hearing on 2020 Step Adjustment

O R D E R N O. 26,504

July 30, 2021

In this order, the Commission authorizes Eversource to recover the annual revenue requirement associated with $123,141,062 of plant additions placed in service in calendar year 2020. Recovery will be made through distribution rates on a service rendered basis beginning August 1, 2021. Eversource recovers distribution rates from all delivery service customers.

I. PROCEDURAL HISTORY

Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource) filed its notice of intent to file rate schedules on March 22, 2019, and on April 26, 2019 filed notice of its intent to file schedules for permanent rates. On October 9, 2020, all parties filed a settlement agreement on permanent rates (Settlement Agreement), which was approved by the Commission through Order No. 26,443 (December 16, 2020). The Settlement Agreement established permanent rates based on a 2018 test year. Among its provisions, the Settlement Agreement provided for three annual step increases to account for plant placed in service in calendar years 2019, 2020, and 2021.

On May 3, 2021, Eversource filed a petition requesting recovery of $11,126,440 in revenue requirement associated with $124,215,062 of plant additions placed in service during calendar year 2020, the second step increase established by the Settlement Agreement. Eversource filed supporting pre-filed testimony and related attachments associated with this capital investment. The Commission issued a supplemental order of notice on June 3, 2021, scheduling a hearing which was held on July 19, 2021.

The initial filing, testimony, exhibits and other docket filings, other than any information for which confidential treatment has been requested of or granted by the Commission, are posted at: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-057.html.

II. POSITIONS OF THE PARTIES

A. Eversource

Eversource testified in support of its proposed step increase associated with $124,215,062 of plant additions placed in service in 2020, explaining the development of projects completed in 2020, from the initiation of a project to placement of plant into service. Eversource maintained that all capital investments included in its second step increase request were prudently incurred, used and useful.

Eversource discussed several projects and project accounts at hearing. First, Eversource testified about the Welch and Locks Island cable replacement project. According to Eversource, the project was initiated in 2016 to replace two submarine cables installed in the 1940’s and 1960’s, respectively. Eversource acknowledged that although the project was initially budgeted in 2016 at approximately $360,000, the project’s life to date costs totaled approximately $1.8 million. Eversource testified that the project was competitively bid, and that the installation included shoreline infrastructure improvements and redundant systems to increase the cables’ service life and increase reliability.

Eversource discussed the Pemigewasset transformer project, which Eversource acknowledged had increased in cost from approximately $4 million to approximately $6.8 million. According to Eversource, the cost increases were attributable to expanding the control house, testing and commission costs, and animal protection equipment, among other things. With regard to testing and commissioning, Eversource acknowledged that voltage issues were discovered during testing that were attributable to an engineering contractor, which ultimately resulted in higher costs, including internal labor. Eversource emphasized that the engineering contractor performed all necessary revised engineering at no additional cost. Eversource argued that the testing did what it was intended to do by uncovering a problem before the project was installed and operational, which mitigated costs and damages, and therefore the associated costs are reasonable.

Eversource discussed its treatment of costs related to replacing plant in service when a third party damages utility property. Eversource explained that once the Company knows that the damage was caused by a third party, and the third party is identified as responsible for payment, the Company will bill the individual or insurance company for the damages. Once Eversource generates the bill for damages, Eversource credits the work order within the annual project in the calendar year that the Company actually bills the third party. Eversource argued that it would be inappropriate to assume recovery of damaged plant is a given, and stated that this topic should be addressed during its upcoming business process audit.

Eversource also discussed its practice of treating load tap changers and controls, devices associated with transformers, as separately capitalized units of property as opposed to treating the item as a maintenance expense. Eversource acknowledged that the item may be replaced before the retirement of the transformer. Eversource highlighted the improved functionalities of newer changers and controls as increasing service quality and reliability. Eversource stated that it had given the item consistent accounting treatment in accordance with written company policy since 2012, and that no issues with its treatment of the cost were raised during its most recent rate case in the instant docket. Eversource argued removal of the costs would be unreasonable and inappropriate.

B. Office of the Consumer Advocate

Regarding the accounting treatment of load tap changer controls and utility property damaged by third parties, the OCA encouraged the Commission to adopt the findings of the audit (Exhibit 63), including treating load tap changer controllers as a maintenance expense.

The OCA declined to take a position on the Welch and Locks Island cable replacement project and the Pemigewasset transformer project items at hearing.

The OCA noted that Eversource carries the burden to show that the costs it seeks recovery of in this hearing were prudently incurred, as well as used and useful.

C. Department of Energy

The Department of Energy expressed generalized concerns about cost overruns of projects in this matter. Regarding the Pemigewasset transformer project, Energy recommended that at least $911,000 in costs attributable to the third party engineering contractor's error be disallowed as imprudently incurred. These costs include Eversource's additional internal engineering efforts, construction, testing and commissioning, and other costs identified by Eversource as resulting from the contractor's error but not covered under its contract. *See* Exh. 64 at 55-56. According to Energy, Ratepayers should not responsible for incremental costs associated with the error of a third party consultant.

Regarding the load tap charger controllers, Energy recommended that the item should be removed from the 2019 and 2020 step increases, and treated as a maintenance expense as recommended in the audit report. *See* Exhibit 63 page 21. Energy recommended further examination of the accounting treatment given to damaged utility property, including examining disincentives to the utility to seek the identify third parties who damage utility property. With those exceptions noted, Energy otherwise agreed with Eversource that the costs proposed for inclusion in the step increase are for used and useful facilities, and were prudently incurred. Subject to the exceptions noted, Energy concluded that the resulting rates are just and reasonable, and recommended that the Commission approve the filing subject to the exceptions it raised.

III. COMMISSION ANALYSIS

Step adjustments are a mechanism the Commission has approved for limited use between rate cases to allow a utility to collect additional revenue on investments that are generally non-revenue producing and are made to improve safe and reliable service. Step adjustments are generally limited in scope and allow recovery for investments similar to those that have been reviewed in the underlying rate case that established the step adjustment provision. Utilities have the burden of showing that capital investments included in step adjustments are prudent, in service, and used and useful.

In order to approve this step increase, the Commission must determine whether the investments included in the calculation of the step increase are prudent, used and useful under RSA 378:28. As noted in the record, both Energy and the Company view the majority of projects requested for recovery within the step adjustment to be used and useful, as well as prudently incurred, and that the requested rates are just and reasonable.

Concerning the subset of costs associated with the Pemigewasset transformer project related to the engineering contractor's error, we agree with Energy that some of the costs were not prudently incurred. Eversource acknowledged that it incurred additional costs as a direct result of a third party contractor's error, but that those costs were not covered by its contract. Exh 64 at 55. At hearing, Eversouce went on to state that its contracts limit contractor liability, that it did not seek any "insurance" claim through the contractor for "consequential" damages, and that its own internal reviews did not catch the issue. Hearing Transcript of July 19, 2021 (Tr.) at 78-79. The costs attributable to the third party engineering contractor's error include: additional internal engineering efforts, construction, testing and commissioning, and other costs resulting from the contractor's error but not covered under its contract are disallowed as imprudently incurred. *See* Exh. 64 at 55-56. Based on the testimony, we do not find that Eversource has met its burden to show that these consequential costs were prudently incurred, and disallow $911,000 in investment costs associated this project.

Concerning the Welch and Locks Island cable replacement project, the Commission notes that testimony established that the underlying analysis and estimate regarding this project in 2016 was insufficient. Eversource witnesses acknowledged the lack of specific information related to the initial decision to proceed with this project. *See, e.g.*, Tr. at 58-59, 127-128 (acknowledging the original project authorization form did not contain a cost basis for the original $360,000 estimate). The Commission gives weight to Eversource's subsequent project analysis, Exh. 64 at 1-7, and the fact that the project was later competitively bid two times. Exh. 64 at 1, Tr. at 17. Further, Eversource indicated that the approval process has been improved, requiring specific detailed information to support estimates and decision-making. Tr. at 127-131. In addition, Energy and Eversource indicated that a review of this process will be part of the

Business Process Audit to be conducted pursuant to the Settlement Agreement in the underlying rate case. Tr. at 151, 158. We conclude that the costs incurred prior to the supplemental authorization approval were imprudently incurred, and disallow $163,000 in in investment costs associated with this project. Exh 64 at 1 (identifying $163,000 in charges to the project total incurred prior to the time of supplemental authorization and based upon the initial decision). In light of the evidence provided in Exhibit 64 regarding supplemental analysis, decision-making, and approval that occurred following the initial decision regarding this project, the Commission finds the project to be used and useful, the remainder of the related costs prudently incurred, with improved processes in place for future projects. Although not relied upon in reaching our decision, we also note subsequent analysis, provided in a record request, showed that the diesel and solar alternatives would have resulted in the higher costs while providing lower reliability for shorter time periods than the underwater cable. Exh 66. The Commission advises Eversource that a thorough review of alternatives is expected for large projects and that Eversource risks recovery when alternatives are not fully analyzed.

Turning to the accounting treatment of property damage attributable to third parties, we note that this issue was discussed in the proceeding regarding the first step increase in this docket. *See* Order No. 26,439 at 7 (December 23, 2020). We agree with Eversource that the upcoming business process audit provides an appropriate opportunity for further review of this practice and expect to see analysis and recommendations regarding this issue addressed in that audit. In light of that, we approve associated costs in this matter for recovery as proposed in Eversource's petition, subject to reconciliation.

Regarding Eversource's accounting treatment of load tap changer controls, we agree with Energy and the audit report's conclusion that the item should be accounted for as a maintenance expense pursuant to 18 C.F.R. § 367.59 (c)(3). We find it compelling that Eversource itself historically interpreted the federal regulation in the same manner as recommended by Energy and conceded at hearing the language of the regulation had not changed. We direct that Eversource implement this accounting change on a going forward basis.

Subject to the determinations above, we find the expenditures which are the subject of Eversource's petition to be prudent, used, and useful, and we find the resulting rates to be just and reasonable, pursuant to RSA 374:1, RSA 374:2, RSA 378:7 and RSA 378:28.

Based upon the foregoing, it is hereby

ORDERED, that the step adjustment to be added to distribution rates, as calculated by Eversource in its Step 2 filing of May 3, 2021, and supplemented by testimony and record request responses for its 2020 capital investments, as reduced for the disallowance for specified portions of the Pemigewasset transformer project and the Welch and Locks Island cable replacement project as discussed in the body of this order, is hereby APPROVED; and it is

FURTHER ORDERED, that Eversource is authorized to implement the rates approved herein on a service-rendered basis effective August 1, 2021; and it is

FURTHER ORDERED, that Eversource shall file tariff pages as required by N.H. Code Admin. R., Part Puc 1603, conforming to this order within 15 days of the date hereof.

By order of the Public Utilities Commission of New Hampshire this thirtieth day of July, 2021.

Dianne Martin
Chairwoman

Daniel C. Goldner
Commissioner

Service List - Docket Related

Docket# : 19-057

Printed: 7/30/2021

Email Addresses

ClerksOffice@puc.nh.gov
palvarez@wiredgroup.net
mbirchard@keyesfox.com
aboyd@acadiacenter.org
brianna@cleanenergynh.org
kelly@cleanenergynh.org
brian.d.buckley@energy.nh.gov
rburke@nhla.org
richard.t.chagnon@energy.nh.gov
pradip.chattopadhyay@oca.nh.gov
jessica.chiavara@eversource.com
john@johncoffman.net
roger@fsconline.com
kristi.davie@eversource.com
johndefever@yahoo.com
allen.desbiens@eversource.com
paul.b.dexter@energy.nh.gov
jdonahue@preti.com
pearl.donohoo-vallett@brattle.com
jay.e.dudley@energy.nh.gov
stephen.r.eckberg@energy.nh.gov
eemerson@primmer.com
matthew.fossum@eversource.com
thomas.c.frantz@energy.nh.gov
mhorne@hcc-law.com
tklaes@blueridgecs.com
donald.kreis@oca.nh.gov
erica.menard@eversource.com
tmlarkinassociates@gmail.com
karen.j.moran@energy.nh.gov
scott@sjmuellerlaw.com
dmullinax@blueridgecs.com
rnelson@strategen.com
elizabeth.r.nixon@energy.nh.gov
amanda.o.noonan@energy.nh.gov
ocalitigation@oca.nh.gov
rebecca.ohler@des.nh.gov

rorie.e.patterson@energy.nh.gov
melissa.price@eversource.com
agustin.ros@brattle.com
sanem.sergici@brattle.com
Christa.Shute@oca.nh.gov
christopher.skoglund@des.nh.gov
stower@nhla.org
jacqueline.m.trottier@energy.nh.gov
dvenora@keeganwerlin.com
david.k.wiesner@energy.nh.gov
jrw@psu.edu
craig.wright@des.nh.gov

STATE OF NEW HAMPSHIRE
before the
PUBLIC UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY

Notice of Intent to File Rate Schedules

Docket No. DE 19-057

MOTION FOR RECONSIDERATION AND CLARIFICATION OF ORDER NO. 26,504

Pursuant to New Hampshire Code of Administrative Rules Puc 203.07 and RSA 541:3, Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource" or "the Company") hereby moves for reconsideration and clarification of Order No. 26,504 (July 30, 2021) (the "Order") in the instant docket. The Order ignores or overlooks relevant facts and law, alters items previously decided without justification, and does not validate the conclusions it reaches. Moreover, the Order creates confusion and uncertainty that must be addressed if Eversource is to comply with its terms. In support of this motion, Eversource states as follows:

I. BACKGROUND AND PROCEDURAL HISTORY

1. On March 22, 2019, Eversource filed with the Commission its Notice of Intent to File Rate Schedules pursuant to N.H. Code Admin. Rule Puc 1604.05 pertaining to its request for temporary rates. On May 8, 2019, the Commission issued Order No. 26,250, suspending Eversource's proposed tariff for a temporary rate increase pending further investigation and on May 28, 2019, the Company submitted its permanent rate filing seeking an increase in rates effective July 1, 2019. Over the ensuing year and a half (including the allowance created by Governor Sununu's extension of the Commission's authority to suspend rate schedules by six months, from 12 to 18 months in his April 24, 2020, Executive Order #29, issued pursuant to Executive Order 2020-04), Eversource and numerous parties engaged in discovery, technical

sessions, and other discussions culminating in a Settlement Agreement (the "Settlement Agreement") on permanent rates that was filed with the Commission on October 9, 2020 and addressed in hearings at the end of October 2020. On December 15, 2020, the Commission issued Order No. 26,433 approving the Settlement Agreement.

2. Pursuant to Section 10 of the Settlement Agreement, Eversource is allowed three step increases to account for plant placed in service in calendar years 2019, 2020, and 2021. Appendix 5 to the Settlement Agreement identified the projects Eversource anticipated placing in service in calendar years 2019 and 2020 as part of the first and second step adjustments. The first step adjustment covering plant additions in calendar year 2019 was adjudicated in December 2020 and, by Order No. 26,439 (December 23, 2020), was approved as filed. The rate changes necessary to account for the Settlement Agreement as well as the first step adjustment occurred simultaneously on January 1, 2021.

3. On May 3, 2021, Eversource submitted its documentation in support of the second step adjustment consistent with the Settlement Agreement. Under the terms of the Settlement Agreement, the Company was to provide certain information with the second step submission, including: extensive information on the amount of the investments to be included in the step adjustment; detailed project descriptions including the initial budget; the final cost and date on which each project was booked to plant in service; and certain supporting documentation identified in the Settlement Agreement. *See* Settlement Agreement at Section 10.3. The documentation followed the template for documentation agreed to with the Staff[1] for the initial step. *Id.* Under the Settlement Agreement, if the actual costs for the relevant projects resulted in

[1] At the time of the underlying rate case and the Settlement Agreement, the Staff was the Staff of the Commission, but by the time of the hearing on the second step adjustment the Staff had been transferred to the newly-created New Hampshire Department of Energy. For ease, references to "Staff" in this submission will mean either the Staff of the Commission or the Department of Energy as is appropriate for the context.

a lower than agreed-upon revenue requirement cap of $18 million, the actual amounts were to be used to calculate the step adjustment. In this case, the revenue requirement based on actual costs came in below the cap and Eversource proposed to recover the actual costs through the step adjustment.

4. The second step adjustment proposed that amended rates take effect on August 1, 2021, as contemplated in the Settlement Agreement. On June 29, 2021, the Commission issued a supplemental order of notice pertaining to the second step setting a hearing for July 19. Following that hearing, on July 30, 2021, the Commission issued the Order, which is the subject of this motion.

5. In the Order, the Commission approved the majority of the projects and project costs for recovery as proposed in Eversource's step adjustment filing, with some significant exceptions. First, despite finding the Pemigewasset Substation Project to be prudent, used and useful, the Commission disallowed $911,000 of the total costs incurred for its development. As part of every distribution project completed by the Company, there are testing protocols in place to assure that the new equipment is functioning correctly and as designed before the equipment is energized and connected to the distribution system. An engineering design flaw was detected during the testing phase of the Pemigewasset Substation Project – a hugely complex, multi-dimensional undertaking – that had to be resolved before the project could be energized and placed into service. The third-party engineering firm took responsibility for the error and reproduced its work to correct for the engineering design flaw.

6. The costs that the Commission disallowed are the costs the Company incurred for additional internal engineering efforts, construction, testing and commissioning of the corrected substation design. These costs were not – and should not be – covered by the engineering firm's

contract. Yet, the Commission found that the costs that the Company incurred resulting from the contractor's error but not covered under its contract were "disallowed as imprudently incurred." Order at 6. With respect to the replacement of a failing submarine cable providing service to Welch and Lockes Islands in Lake Winnepesaukee, the Commission again found the project prudent and used and useful but disallowed a portion of the project's costs. With minimal explanation, the Commission disallowed $163,000 in costs finding that "the costs incurred prior to the supplemental authorization approval were imprudently incurred." Order at 7.

7. In the Order, the Commission identified two additional items with which it had concerns. With respect to the accounting treatment of property damage attributable to third parties, the Commission concluded that the matter would be addressed in the Business Process Audit ("BPA") specified in the Settlement Agreement. In the interim, however, the Commission approved the costs identified in Eversource's submission for recovery, "subject to reconciliation." Order at 7. Lastly, the Commission agreed with certain findings of the audit report on the first step, on which there had been no Staff recommendation or other process, that load tap changer controls ("LTCCs") should be treated as an expense item, rather than a capital item "on a going forward basis." Order at 8.

8. On each of these four items, and as discussed more fully below, the Order overlooks or disregards relevant information and should be reconsidered and/or clarified.

II. LEGAL STANDARD

9. Pursuant to RSA 541:3, the Commission may grant rehearing or reconsideration when a party states good reason for such relief. *Public Service Company of New Hampshire*, Order No. 25,361 (May 11, 2012) at 4. Good reason may be shown by identifying new evidence that could not have been presented in the underlying proceeding or by identifying specific

matters that were overlooked or mistakenly conceived by the deciding tribunal. *Id*. at 4-5. A successful motion for rehearing does not merely reassert prior arguments and request a different outcome. *Id*. at 5. Eversource submits that for the reasons set out below, the Commission's decision overlooks or mistakenly conceives relevant facts and law and improperly adjusts findings and conclusions in prior orders. Accordingly, reconsideration is proper.

III. ARGUMENT

10. As described above, the Commission concluded that it would disallow recovery of $911,000 in costs pertaining to the Pemigewasset Substation. That project related to extensive, necessary work within the station including replacement of an existing, overloaded transformer with a new transformer, as well as the replacement of other aged equipment and expanding the control house at the station to accommodate the required new control equipment. Ex. 64 at 29. For that project, Eversource, as part of its standard practice, retained an outside engineering firm to conduct detailed engineering work on the substation pertaining to this necessary work. Transcript ("Tr.") at 68. The engineering work was examined through the project review and budgeting processes consistent with Eversource's capital authorization practice. Tr. at 69-73. Eversource utilizes sophisticated quality-control testing protocols to assure that any new equipment being installed on the system is functioning as designed and will integrate with the existing components of the distribution system safely and reliably. The quality-control testing is designed to be a checkpoint to reveal any anomalies that could cause system faults or cascading failures when the component is energized and placed into service. At the stage that Eversource was testing the newly installed equipment prior to commissioning, Eversource discovered incorrect voltage on the synch scope, requiring a change to the design. Ex. 64 at 31; Tr. at 74-75. Because the error was attributable to the work of the engineering firm, the firm was required to

conduct additional work to correct the identified problems at its cost. Tr. at 78. The additional engineering required additional steps from the Company, including construction and testing, all with the purpose of assuring that the newly installed equipment would function properly when integrated into the surrounding, inter-dependent components and not be prone to some kind of failure. Ex. 64 at 55-56; Tr. at 79-80. It is the additional costs following the identification of the design flaw the Commission disallowed.

11. With respect to these additional costs, the Commission summarily and erroneously concluded that "[b]ased on the testimony, we do not find that Eversource has met its burden to show that these consequential costs were prudently incurred, and disallow $911,000 in investment costs associated this project." Order at 6. This conclusion overlooks relevant facts and is without adequate foundation.

12. There are several reasons that the Commission's finding is in error. First, the Commission concluded that the identified costs were imprudent, but it never specified the particular basis for its conclusion. Pursuant to RSA 363:17-b, III, orders of the Commission are to contain a "decision on each issue including the reasoning behind the decision." In this case, the Commission made a few factual statements about the costs and the engineering firm's liability apart from the conclusory statement. However, the actual conclusory statement that Eversource failed to meet its burden to show the costs were prudently incurred fails to cite any reasoning for that conclusion. There is no statement as to the reason that the costs are claimed to be imprudent, which is the direct implication of a finding that the Company failed to meet its burden.

13. Significantly, the conclusory statement on the Company's alleged failure to meet the standard starts with the words "Based on the testimony, … ." However, the only testimony

in the proceeding is from Eversource witnesses who, in both written and oral testimony, provided substantial information on the details involved in the project and the interactions with the engineering firm and described how these acts were prudent. Ex. 59 at 24 (red); Tr. at 22. There is no testimony before the Commission that contradicts the evidence in the record put forth by the Company. No other witnesses testified on the matters and there is no evidence demonstrating that Eversource was not prudent. Accordingly, to the extent "the testimony" supports any conclusion, it can only be that the project and its costs were prudent. In that the Commission stated that its conclusion was based upon the testimony and that the Commission's conclusion is contrary to the evidence in testimony, it should be reconsidered.

14. Furthermore, in reaching its decision the Commission does not define or explain what the standard of prudence is, nor how it believes Eversource failed to meet that standard in this instance. In New Hampshire:

> The prudence standard is one of the specific standards that has been developed by the Court to govern the inclusion or exclusion of costs for ratemaking purposes. *Appeal of Conservation Law Foundation*, 127 N.H. 606, 637 (1986).
>
> Prudence is "essentially an analogue of the common law negligence standard". *Id*. "While the scope of the prudence principle is by no means clear, it at least requires the exclusion from rate base of costs that should have been foreseen as wasteful." *Id*. "[P]rudence judges an investment or expenditure in the light of what due care required at the time an investment or expenditure was planned and made." *Id*. at 638.
>
> The test of due care asks what a reasonable person would do under the circumstances existing at the time of a decision. *Fitzpatrick v. Public Service Co*. of N.H., 101 N.H. 35 (1957). Stated differently, a lack of due care is the failure to use that degree of care that the ordinary reasonably careful and prudent person would use under like circumstances.

Public Service Company of New Hampshire, Order No. 20,503, 77 NH PUC 268, 270 (1992); *see also Public Service Company of New Hampshire*, Order No. 25,565 (August 27, 2013) at 20 ("When reviewing whether a utility has been prudent in its decision making, [the Commission] 'may reject management decisions when inefficiency, improvidence, economic waste, abuse of discretion or action inimical to the public interest are shown.'") (*quoting Appeal of Easton*, 125 N.H. 205, 215 (1984)). In this case, the Commission found that the Pemigewasset Substation Project, on the whole, was prudently undertaken and is used and useful in providing service to customers. In addition, pre-completion testing is a critical part of the project installation process, which is specifically and diligently applied to identify and fix potential anomalies that could cause damage and cost if installed without discovery of those anomalies. Lastly, there is no evidence that the Company could have done anything different in relation to the contractor's liability, nor is any such evidence stated in the decision. Without any statement of the standard in the decision, nor any analysis matching up the evidentiary facts with the standard, the summary conclusion stating that the Company has not met its burden falls far short of what is required by law as a basis for a disallowance.

15. Without any weighing and discussion of the record evidence, it is not possible to reconcile the fact that the Commission found that: (1) the Pemigewasset Substation Project was prudently constructed and is used and useful in the service of customers; and (2) all associated costs of the project are prudent, *except* for the costs incurred to correct an error before that error resulted in the failure of a significant piece of newly installed equipment. Thus, the evidence does not support the conclusion that the costs are imprudent.

16. Further, as quoted above, the standard for prudence is not perfection. Rather, it is whether the utility exercised due care in acting as a reasonable person would when completing the project, or whether the company was undertaking work that it could foresee would be wasteful. In this case, the Company retained a consultant to perform the complex, specialized engineering work required for the substation project, which is an established industry practice, *i.e.,* specialized engineering work is typically needed on larger scale projects and is warranted

given the reliance the system will have on that component. The consultant's work was conducted professionally with oversight by the Company and subject to appropriate contract terms used in the industry for this type of work, and there is no evidence that the Company's contracting terms with the consultant fell below industry practice. There is nothing to indicate that Eversource did, or failed to do, anything other than exercise appropriate due care in the engineering for the project; nor does the Order cite to any particular basis or shortfall as proof that the Company "failed to meet its burden."

17. Upon testing the equipment, the Company determined that there were anomalies that had to be addressed before the equipment could be commissioned and placed into service. As Eversource explained at hearing:

> We perform our review before it goes to construction…. Had we not done this testing, we probably would have energized the transformer and created a -- and maybe failed the transformer. You know, we test everything before we energize it. And, in this case, that testing process did exactly as it was designed to do, it detected a wiring error, and helped us figure out how to correct it.

Tr. at 79-80. In other words, the testing was appropriate and consistent with standard protocols to address any issues that might not previously have been addressed. And, in this case, it revealed an anomaly that required correction. Thus, the Company did exactly what it should do to verify the operability of system components before commissioning those components on the system. The Company addressed the anomaly to make sure that the project could be completed for the purpose that it is meant to serve. There is no step in the process where the Company fell below the standards of reasonable care and the Order does not cite to a single point of failure warranting the conclusion that the Company failed to meet its burden under the applicable standard established in New Hampshire law.

18. The Order appears to assume that any costs incurred following the testing are, by definition, imprudent because they might have been avoided under different facts. Although hindsight may indicate that the situation could have unfolded differently, the potential for different facts does not dictate whether Eversource acted prudently, consistent with New Hampshire law and precedent. As quoted above "The test of due care asks what a reasonable person would do under the circumstances existing at the time of a decision." *Public Service Company of New Hampshire*, 77 NH PUC at 270. At the time that it conducted its testing and discovered the issue, Eversource had to decide whether to correct the error and finish the project, leave the error uncorrected and potentially fail an expensive piece of newly installed equipment, or abandon the project. In that this was a necessary project, abandoning the project was not an option. Likewise, installing and commissioning a piece of equipment Eversource now knew to be faulty was not an option. Accordingly, in line with the degree of care that an ordinary reasonably careful and prudent person would have used under like circumstances, Eversource corrected the error and completed the project. Thus, there is nothing in the record demonstrating that Eversource exercised anything other than the standard of reasonable care called for and no basis for a disallowance. Thus, the Commission's Order should be reconsidered.

19. With respect to the cable replacement project, there is, likewise, no basis for the Commission's conclusion and reconsideration is appropriate. This project involved the replacement of cables serving the year-round residents of Lockes and Welch Islands on Lake Winnipesaukee, who had been served by submarine cables that were more than 60 years old and that were failing. Tr. at 16. The Company had been reviewing the need for the project for some time and engineering, permitting and other work ultimately began in 2016. Tr. at 16-17. As that work progressed, and once it had gone out for bidding, it became clear that the initially approved

amount of $360,000 for the project was inadequate. Tr. at 17. Therefore, a supplemental funding request was completed and approved. A second round of bidding was conducted to assure that the Company was capturing and planning for the lowest cost for the project with the best information. Tr. at 17-19.

20. As with the substation project, the testimony and evidence in the docket supports the prudence of the project and there is no evidence to the contrary. No party sought a disallowance of costs relating to this project. The Staff asked questions about the project and solicited information during the hearing; however, no party requested that the Commission reject any of the costs. In fact, in its closing, the Staff stated its position that, with exception of the Pemigewasset Substation and the costs of the LTCCs, "the Regulatory Support Division views the projects requested for recovery in this step as used and useful, their costs as prudently incurred." Tr. at 153. Accordingly, the Staff supported the prudence of the same project that Eversource testified was prudent and it is unclear on what basis the Commission determined to disallow costs without any support in testimony and without any proposal for disallowance.

21. The only justification stated in the Order for disallowance is that "the costs incurred prior to the supplemental authorization approval were imprudently incurred." Order at 7. The Commission points to no facts, information, or reasoning indicating a basis for treating the $163,000 in disallowed costs any differently than any other costs for this project. The costs were incurred consistent with an initial authorization that was previously, and properly, approved in 2016. Ex. 64 at 1, 3. Although the Commission asserts that the initial authorization was lacking in detail, there is nothing in the Order, nor in the record, that indicates that the $163,000 spent pursuant to that properly approved funding request was improper, inappropriate or

imprudent. The fact that more detail would have been preferred does not mean that the engineering costs that were incurred pursuant to that initial authorization were imprudent.

22. As noted above, the evaluation of "prudence" is a test of due care and asks whether the utility did what a reasonable person would do under the circumstances existing at the time of a decision. The Commission's determination appears to be based almost entirely on the belief that additional detail in the initial authorization would have been better. Eversource does not dispute that providing additional detail and support in project authorization documents may be preferred in any given instance. However, the fact that the Commission seeks more detail does not end the Commission's inquiry and is not a sufficient basis to deny cost recovery. In that the Commission overlooked or mistakenly conceived the facts and the record as well as the relevant legal standard, reconsideration is proper.

23. Next, Eversource seeks both reconsideration and clarification with respect to the accounting treatment of LTCCs. As described at the hearing:

> A substation transformer, especially newer ones, have, in addition to the transformer, there is a separate mechanical piece of equipment that allows you to regulate the voltage coming out of that transformer within a certain range, generally plus or minus 10 percent. That device is called a "load tap changer". It changes what are called "taps" within the transformer, changes them under load, hence the name "load tap changer". Associated with that load tap changer is a control, which monitors the voltage, it has program settings. And, as long as -- if the voltage goes outside those limits that are programmed into the control, it adjusts the taps such that it will change the voltage coming out of that transformer. That's a "load tap changer".

Tr. at 91. Accordingly, an LTCC is a piece of equipment attached to a transformer that aids the transformer in controlling voltage. As Eversource stated, it is common for an LTCC to be replaced separately from the replacement of the transformer to which it is attached. Tr. at 92. Eversource has, since 2012, treated LTCCs as capital items consistent with the relevant FERC regulations. Ex. 63 at 21. In the Order, the Commission concluded that LTCCs should be treated as a maintenance expense item "on a going forward basis." Order at 8. This conclusion requires reconsideration as well as clarification.

24. As to the issue of reconsideration, the Commission's conclusion in the Order runs counter to the express understanding of the Settlement Agreement as approved in Order No. 26,433. The Settlement Agreement specifies the capital projects and capital project types that are to be included in the step adjustments and specifically references LTCCs as a capital item in the steps. *See* Exhibit 58, at page 54 (red), line 99; page 59 (red), lines 104 and 122; and page 60 (red), line 136. Accordingly, it was the express intent of the settling parties, and the Commission, that these be included as a capital item within the step adjustments.

25. As noted, Eversource has been treating LTCCs as a capital item since 2012, including through the time of the audit conducted on the Company's underlying rate case filing. That audit did not identify any issues or concerns with the treatment of LTCCs as a capital item. Consistent with long-standing Commission practice and procedure,[2] the audit report on the rate case was not submitted as a stand-alone document from which the Commission was intended to reach its own conclusions. Rather, the rate case audit was referenced in Staff's written testimony and formed the basis for various recommendations by the Staff which, notably, did not relate to each issue in the audit report, but only to those the Staff viewed as worth noting. *See* Ex. 57. As a result, there was no opportunity for Eversource to address the treatment of LTCCs as a capital item in the context of the rate case hearing. Accordingly, through testimony in the rate case, Eversource had notice and a public opportunity to address the matters deemed relevant from the

[2] *See e.g.*, Docket Nos. DE 20-062, DE 19-105, and DE 19-050 – Staff recommendations filed following the completion of audits of Eversource's storm costs; Docket No. DG 20-105, Staff testimony filed on March 18, 2021 incorporating results of audit report; Docket No. DG 17-048 Staff testimony filed on November 30, 2017 incorporating results of audit report; Docket No. DG 17-070 Staff testimony filed on December 20, 2017 incorporating results of audit report.

audit report; however that notice and opportunity did not extend to the LTCCs, which the Commission has now ruled upon without any process.

26. The Commission's Audit Staff issued its audit report on Eversource's first step in February 2021. From that time to the date of the hearing on the second step in July 2021, nothing further happened with the audit report. There was no report, recommendation, or testimony of the Staff that sought to implement the audit report or any portion of it. *See* Ex. 68. In other words, there was no public indication that there were continuing issues with the items identified in the audit report generally or with LTCCs specifically. Moreover, there was no opportunity for Eversource to explain or defend any position it took relative to the issues identified in the audit report, nor an opportunity to cross-examine Staff on its recommendations. Eversource was confined to responding to questions during the hearing on a matter it was not aware was in issue in this case.

27. The issue with this inadequate process is made more acute by the fact that there is no indication as to the reasons that the audit or the Staff singled out LTCCs for this treatment. As stated in the audit report, "Audit reviewed the FERC reference to account 362, Station Equipment, and agrees that the initial installation of items of property shall be capitalized. The issue here relates to the replacement of property initially capitalized which should then be expensed as replaced." Ex. 63 at 21. Putting aside for the moment whether Eversource agrees with this conclusion (which it does not), this recommendation is based upon the Audit Staff's reading of a particular FERC regulation that applies to more than just LTCCs. Presuming that the Commission is adopting the audit's recommendation as the correct in interpretation and application of the FERC regulation (which it is not), this conclusion creates confusion as to the application of the relevant accounting standards for items other than LTCCs. As an example, in

the case of the Pemigewasset Substation discussed above, Eversource installed a new control house to contain the equipment necessary to control the substation's operation. In doing so, the entire control house was properly treated as a capital item. Should Eversource replace the door to that control house in the future, the audit report would seem to indicate that the door should be treated as an expense item rather than as part of the larger capital asset to which it is affixed. Because there was no opportunity for a public discussion on this issue, the Commission's blanket adoption of the audit report's conclusion raises questions about the accounting treatment of assets other than just LTCCs. The Order overlooks the truncated process and the long-term confusion created by its conclusions and reconsideration is proper.

28. As a further issue regarding the conclusion on the LTCCs, it should be noted that Eversource has treated LTCCs as a capital item and included the LTCCs in the steps because LTCCs are capital items as specified in the Settlement Agreement. Therefore, Eversource's rates reflect the treatment of those devices as capital assets and Eversource's current rates include the revenue requirement associated with the LTCCs, rather than the full cost of those items as a maintenance expense. Accordingly, should the Commission's conclusion stand, provision must be made within Eversource's rates to allow for recovery of the costs as an expense item, rather than capital.[3] That shift would be best accomplished in a rate case where other changes affecting costs and revenues could be properly addressed. In that the Order overlooks the need for a rate adjustment, reconsideration on this item is appropriate.

29. Lastly, if reconsideration is not granted, or if it is, but is conditioned or maintains the change between capital and expense treatment, additional clarification is needed. In

[3] Similarly, in 2019 Eversource transitioned from treating Enhanced Tree Trimming (ETT) as a capital item to an expense item based upon the Commission's preference. To do so required an adjustment to Eversource's rates to account for that shift. *See* Order No. 26,112 (March 12, 2018).

particular, the Order specifies that the adjustment between capital and expense will be on a "going forward basis." Order at 8. The Order, however, does not define a date from which this adjustment is to occur. In other words, going forward from when? Based on the language in the Order, it appears that the adjustment was not intended to occur for this second step adjustment for projects in service in calendar year 2020. However, it is not clear whether the Commission would intend for it to apply to the third and final step adjustment for calendar year 2021 projects. In that 2021 is more than half complete, and that LTCCs have been treated as a capital item through the rate case and the first two step adjustments, it would be eminently reasonable to include the LTCCs as a capital asset for 2021 and to make the adjustment no earlier than calendar year 2022, subject to proper rate treatment until Eversource's next rate case. Eversource submits that should the Commission not delay the shift until Eversource's next rate case, allowing treatment as capital through at least the final step adjustment aligns with the intent of the Settlement Agreement and is otherwise is reasonable and appropriate.

30. In addition to the above items, Eversource requests clarification of one additional item in the Order. With respect to the accounting treatment of property damage claims, as noted in the Order, the issue was raised in relation to the initial step adjustment and was addressed in that order. In that order, the Commission stated:

> [W]e direct Staff to inquire further regarding the Company's treatment of damage to plant from a third party, and the treatment of billing to liable third parties for the repair of damage done to Eversource's facilities. We direct Staff to report on the conclusions they reach following this review, including any further recommendations by Staff regarding the treatment and reporting of how Eversource handles claims for property damage by third parties. Based on Staff's recommendations, as approved by the Commission, the recovery of costs relating to third party property damage may be subject to reconciliation, as appropriate.

Order No. 26,439 at 7 (December 23, 2020).

31. As of the date of this submission, the further inquiry required of the Staff has not begun and the Staff has not created or submitted any recommendations relating to it. This matter may be covered by the BPA, but it is unclear what additional review the Commission anticipates from the Staff. In Eversource's assessment, the Commission should clarify its expectations relative to the Staff review of this item to assure that it does not improperly interfere with any review contemplated in the BPA.

32. Additionally, in the Order (as well as the order on the initial step), the Commission states that the costs included for this item are approved "subject to reconciliation." It is unclear, however, what reconciliation is anticipated here. The Staff has identified some concerns with the manner in which property damage claims are handled; however, this is the extent of Staff's suggestion. There is not, at this point, anything to reconcile and it is unclear how long this issue would remain open. Eversource requests clarification on how long this matter would remain open for reconciliation.

WHEREFORE, Eversource respectfully requests that the Commission:

A. Grant reconsideration and/or clarification as provided above; and

B. Grant such further relief as is just and equitable.

Respectfully submitted,
Public Service Company of New Hampshire d/b/a Eversource Energy
By Its Attorney

Dated: August 27, 2021 By:__________

Matthew J. Fossum
Senior Regulatory Counsel
Public Service Company of New Hampshire d/b/a Eversource Energy
780 No. Commercial Street, P.O. Box 330
Manchester, NH 03105-0330
(603) 634-2961
Matthew.Fossum@eversource.com

CERTIFICATE OF SERVICE

I hereby certify that, on the date written below, I caused the attached Motion to be served pursuant to N.H. Code Admin. Rule Puc 203.11.

____August 27, 2021__ Date

_ ___ Matthew J. Fossum

STATE OF NEW HAMPSHIRE

COMMISSIONER
Vacant

DEPUTY COMMISSIONER
Christopher Ellms, Jr.

TDD Access: Relay NH
1-800-735-2964

Tel. (603) 271-3670

FAX No. 271-1526

Website:
www.energy.nh.gov

DEPARTMENT OF ENERGY
21 S. Fruit St., Suite 10
Concord, N.H. 03301-2429

September 2, 2021

Dianne Martin, Chairwoman
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301

Re: Docket No. DE 19-057, Public Service Co. of New Hampshire d/b/a Eversource Energy
Notice of Intent to File Rate Schedules – Second Step Adjustment
Department of Energy Response to Eversource Motion for Reconsideration

Dear Chairwoman Martin:

Attached please find the Department of Energy Regulatory Support Division's Reply to Public Service Company of New Hampshire d/b/a Eversource Energy's Motion for Reconsideration and Clarification. Pursuant to the Secretarial Letter issued on March 17, 2020 this motion is being submitted electronically and hard copies will not follow unless requested. If you have any questions about the reply, please feel free to contact me.

Thank you for your attention to this matter.

Sincerely,

/s/ Brian D. Buckley

Brian D. Buckley
Staff Attorney/Hearings Examiner
New Hampshire Department of Energy

Cc: Service List (electronically)
Attachments

Docket #: 19-057 **SERVICE LIST - DOCKET RELATED - Email Addresses** Printed : 9/2/2021

ClerksOffice@puc.nh.gov

aboyd@acadiacenter.org
agustin.ros@brattle.com
allen.desbiens@eversource.com
amanda.o.noonan@energy.nh.gov
brian.d.buckley@energy.nh.gov
brianna@cleanenergynh.org
christopher.skoglund@des.nh.gov
craig.wright@des.nh.gov
david.k.wiesner@energy.nh.gov
dmullinax@blueridgecs.com
donald.kreis@oca.nh.gov
dvenora@keeganwerlin.com
eemerson@primmer.com
elizabeth.r.nixon@energy.nh.gov
erica.menard@eversource.com
jacqueline.m.trottier@energy.nh.gov
jay.e.dudley@energy.nh.gov
jdonahue@preti.com
jessica.chiavara@eversource.com
john@johncoffman.net
jrw@psu.edu
karen.j.moran@energy.nh.gov
kelly@cleanenergynh.org
kristi.davie@eversource.com
matthew.fossum@eversource.com
mbirchard@keyesfox.com
melissa.price@eversource.com
mhorne@hcc-law.com
ocalitigation@oca.nh.gov
paul.b.dexter@energy.nh.gov
pearl.donohoo-vallett@brattle.com
rburke@nhla.org
rebecca.ohler@des.nh.gov
richard.t.chagnon@energy.nh.gov
roger@fsconline.com
rorie.e.patterson@energy.nh.gov
sam@cleanenergynh.org
sanem.sergici@brattle.com
scott@sjmuellerlaw.com
stephen.r.eckberg@energy.nh.gov
stower@nhla.org
thomas.c.frantz@energy.nh.gov
tklaes@blueridgecs.com

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

DE 19-057

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
D/B/A EVERSOURCE ENERGY

Notice of Intent to File Rate Schedules

DEPARTMENT OF ENERGY'S RESPONSE TO EVERSOURCE MOTION FOR RECONSIDERATION AND CLARIFICATION OF ORDER NO. 26,504

On August 27, 2021, Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource") filed a Motion for Reconsideration and Clarification of Order No. 26,504 (Motion). The Department of Energy Regulatory Support Division ("Division") hereby responds to this Motion and states as follows:

1. Under RSA 541:3, the Commission may grant rehearing when a party states good reason for such relief. A successful motion for rehearing does not merely reassert prior arguments and request a different outcome. *Public Service Company of New Hampshire*, Order No. 25,239 at 8 (June 23, 2011). RSA 541:4 requires a motion for rehearing "shall set forth fully every ground upon which it is claimed that the decision or order complained of is unlawful or unreasonable." While the Division takes no position on whether Order No. 26,504 is unlawful or unreasonable, we take this opportunity to provide further information in response to some of the points of contention identified in the Motion, while also correcting certain factual inaccuracies.

2. Eversource asserts that the Commission has erred in disallowing Eversource's recovery of $911,000 in costs associated with the error of an engineering contractor responsible for work on the Pemigewasset Substation project. According to Eversource, "the only testimony in the proceeding is from Eversource witnesses who, in both written and oral testimony, provided

substantial information on the details involved in the project and the interactions with the engineering firm and described how these acts were prudent." Motion at 6-7. While it is true that the Eversource witnesses were the only ones to testify, upon cross-examination by the Division, the Eversource witnesses made statements which speak directly to the imprudence of the action that led to the $911,000 disallowance.

3. When asked whether the Company took any action to try to recover some of the incremental project costs associated with the contractor's error from the contractor, or the contractor's insurer, the Company's witness stated:

> We did not seek any insurance claim, per se, through [the contractor]. We do have contracts that have been negotiated with all of our engineering vendors, we have a lot of them, that limit the amount of liability that they are liable for. So, in this case, they did complete all of the additional engineering at their own cost, but their contract doesn't make them liable for the -- I don't know if the word is correct, but I would say -- I'd call them "consequential" damages.

July 19, 2021 Transcript (Tab #178) at 78-79.

4. For several pages, the Motion builds a straw man argument regarding why the Commission viewed the referenced "consequential damages" as relating to imprudent project management practices. The Motion then rebuts that straw man by citing Eversource's detection and remedy of the contractor error before any equipment was actually damaged. According to Eversource, without the rigorous testing requirements and oversight by Eversource employees, a transformer could have failed and the costs of the error could have been much higher. *Id*. at 79.

5. What the Motion fails to acknowledge is that the Commission's reference to the testimony more likely related to the prudence of the Company's contracting practice, a practice that in this case directly led to Eversource' inability to recover costs from a contractor, costs that were directly attributable to an error of that contractor. This project and the associated contractor

error simply provided the venue through which this imprudent contracting practice could come to light before the Commission.

6. Eversource argues that "there is no evidence that the Company's contracting terms with the consultant fell below industry practice." Motion at 9. RSA 378:8 declares that "When any public utility shall seek the benefit of any order of the commission allowing it to charge and collect rates higher than charged at the time said order is asked for, the burden of proving the necessity of the increase shall be upon such applicant." Therefore, when requesting recovery of costs associated with this project in customer rates, it is the Company that must provide the evidence of prudence. It is not the responsibility for the Commission or parties to produce evidence of imprudence, as Eversource suggests. Eversource participated in discovery and technical sessions prior to hearing, and provided discovery responses speaking directly to the costs associated with the contractor error, and failed to present evidence for why this contracting practice — which resulted in nearly $1 million in additional costs for this project — was in fact prudent. Eversource's rehearing motion is the first instance the Company has made an argument about the prudence of its contracting practice. If there is a lack of evidence in the record, that lack of evidence is Eversource's responsibility.

7. Furthermore, industry standard practice is by no means a prudence review safe harbor, and has no bearing on whether limiting the liability of their contractor is the prudent choice for Eversource to make on behalf of its ratepayers. If Eversource's practice is to enter into contracts that limit the liability of its contractors (who almost certainly carry liability insurance) when its contractors make an error that costs money, that practice leaves only two places from which to recover those costs: Eversource *shareholders* or Eversource *ratepayers*. If the Commission were to allow Eversource to recover those costs from ratepayers, the Company would have no

motivation to negotiate contracts with vendors that adequately protect Eversource's ratepayers from the imprudent action, or error, of a contractor. The Commission ruled correctly on Eversource's request for recovery of the $911,000 associated with the contractor's error, and should reject Eversource's request for rehearing on this issue.

8. Eversource also seeks reconsideration regarding a $163,000 disallowance of costs associated with the Lockes and Welch Island cable replacement project, arguing that the Commission has overlooked or mistakenly conceived facts relating to that project. Motion at 12. Eversource asserts that no party sought a disallowance of costs relating to the project, and cites the Division's position at closing as supporting the prudence of this investment. Motion at 11. Upon further review, the Division agrees with Eversource that the prudence of the Locke and Welch Island cable replacement project should be reconsidered by the Commission. In light of the disparity between the initial estimate of $360,000 and the supplemental request of $1.9 million, it is unclear from the record whether either of the Company's estimates considered repair options rather than replacement, and why those options — such as cable injection — were not the preferred alternative to total replacement.[1] If the Commission grants Eversource's request for rehearing regarding the cable replacement project, the Commission should consider placing the choice to replace rather than repair the cable within the scope of that rehearing.

9. Eversource also seeks reconsideration and clarification of the Commission's directive that Eversource treat load tap changer controls (LTCCs) as a maintenance expense item on a going forward basis. Eversource supports its request by asserting that after the issue first arose in the audit of the first step, "there was no public indication that there were continuing issues with the items identified in the audit report generally or with LTCCs specifically," and further

[1] The Company's supplemental request form (Exhibit 64, page 6) lists alternatives that were considered as including only distributed generation. Cable repair options appear not to have been considered.

asserts that "Eversource was confined to responding to questions during the hearing on a matter it was not aware was in issue in this case." Motion at 14.

10. In making these process arguments, Eversource overlooks the notice it was afforded, prior to hearing, by: (1) the filing of the audit report on July 9, 2021, ten days prior to the step adjustment hearing; (2) a technical session held on July 14, 2021 where the LTCC issue was a topic of discussion; (3) the submission of the audit as an exhibit pursuant to the remote hearing guidelines prior to the hearing date; (4) the fact that Eversource is given an opportunity to — and did — respond to audit's recommendations within the audit report itself; and (5) the exchange between the Company and the Division that occurred during the discussion of this same exact issue during the Company's last step adjustment hearing, which is excerpted below:

> Q (Buckley) And if, for example, there were some degree of disagreement by the Commission's Audit Staff about treatment, for example, the LTC Controllers that are requested to recover in the step here, as to whether they are minor or major plant, is that something that the Company agrees would be reconcilable after the audit recommendations?
>
> A (Menard) Yes.

December 1, 2020 Hearing Transcript at 62.

> Q. (Buckley) …What happens if Audit determines that [an investment] shouldn't have been included or some portion of that should not have been included in rate base? Is that reconcilable? And how does that happen?
>
> A (Menard) I would assume, and I'm sort of making up the rules here, because this is the first step that we have been through in a while, but I would assume that, if there is anything that comes out of Audit, that we would agree to have some sort of reconciliation. My guess would be it could be included in the next step as a reconciliation, or we could -- yes, that's probably the cleanest, but, you know, we could find some other approach, too, if we needed to.

Id. at 96.

In light of the above-described notice and opportunities to respond to the LTCC issue identified by audit, the Division believes the process afforded to Eversource was more than adequate to satisfy any due process concerns the company has manufactured for the purpose of its rehearing motion. The Commission ruled correctly on the LTCC capitalization issue raised by audit, and should reject Eversource's request for rehearing on this issue.

11. In summary, while the Division takes no position on whether Order No. 26,358 is unlawful or unreasonable, as Eversource contends, we take this opportunity to provide further information in response to some of the points of contention identified in the Motion as a means of further illuminating the record regarding Eversource's newly raised arguments.

WHEREFORE, for the reasons set forth herein, Division respectfully requests that the Commission:

1. Accept the information provided in this Staff response in support of the record in this proceeding; and
2. Grant such further relief as is just, equitable, and appropriate.

Respectfully submitted,

Department of Energy Division of Regulatory Support

By its Attorney,

Brian D. Buckley

Brian D. Buckley, #269563
21 S. Fruit St, Suite 10
Concord, NH 03301
(603) 271-1188
Brian.D.Buckley@Energy.NH.Gov

I hereby certify that, on September 2, 2021, a copy of this Response has been sent electronically to the Service List in this matter.

Brian D. Buckley

Brian D. Buckley

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DE 19-057

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
D/B/A/EVERSOURCE ENERGY

Motion for Reconsideration and Clarification of Order No. 26,504

Order Denying Motion for Reconsideration and
Clarifying Order No. 26,504

O R D E R N O. 26,528

September 27, 2021

In this order, the Commission denies the motion for reconsideration filed by Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource") on August 27, 2021. In addition, the Commission clarifies the aspects of its order for which Eversource sought clarification.

I. PROCEDURAL HISTORY

Eversource filed a notice of intent to file rate schedules on March 22, 2019, and on April 26, 2019, filed notice of its intent to file schedules for permanent rates. On October 9, 2020, all parties filed a settlement agreement on permanent rates ("Settlement Agreement"), which the Commission approved through Order No. 26,443 on December 16, 2020. The Settlement Agreement established permanent rates based on a 2018 test year. Among its provisions, the Settlement Agreement provided for three annual step increases to account for plant placed in service in calendar years 2019, 2020, and 2021.

On May 3, 2021, Eversource filed a petition requesting recovery of $11,126,440 in revenue requirement associated with $124,215,062 of plant additions placed in service during calendar year 2020, the second step increase established by the Settlement Agreement. On July 19, 2021, the Commission held a hearing, and on July

30, 2021, it issued Order No. 26,504 authorizing Eversource to recover annual revenue requirement associated with $123,141,062 of plant additions placed in service in calendar year 2020.

Eversource filed the present Motion for Reconsideration and Clarification of Order No. 26,504 on August 27, 2021. The Department of Energy ("Energy") filed a response on September 2, 2021.

II. POSITIONS OF THE PARTIES

A. Eversource

Eversource seeks reconsideration of three aspects of the Commission's Order. First, it asks that the Commission reconsider disallowing the recovery of $911,000 of the costs it incurred resolving an engineering flaw in its Pemigewasset Substation Project. Second, Eversource seeks reconsideration of the Commission's disallowance of $163,000 of costs incurred replacing a submarine cable in Lake Winnipesaukee. Third, Eversource asks the Commission to reconsider its decision to treat load tap changer controls ("LTCCs") as an expense item rather than a capital item.

In addition, Eversource seeks clarification of the Commission's decision to approve property damage attributable to third parties "subject to reconciliation." Finally, it seeks clarification of the Commission's decision to begin accounting LTCCs as an expense item "on a going forward basis."

B. Department of Energy

Energy urges the Commission to reject Eversource's request for rehearing on the Pemigewasset Substation Project issue and the LTCC accounting issue. It agrees with Eversource, however, that the prudence of the Winnipesaukee cable replacement project should be reconsidered by the Commission in light of the disparity between the initial estimate of $360,000 and the supplemental request of $1.9 million. Energy asserted it is unclear from the record whether either of the Company's estimates considered repair options rather than replacement, and why those options — such as cable injection — were not the preferred alternative to total replacement. Energy's response does not address the issues for clarification raised by Eversource.

III. COMMISSION ANALYSIS

A. Standard of Review

The Commission may grant rehearing or reconsideration for "good reason" if the moving party shows that an order is unlawful or unreasonable. RSA 541:3; RSA 541:4; *Rural Telephone Companies*, Order No. 25,291 (November 21, 2011); *see also Public Service Company of New Hampshire d/b/a Eversource Energy*, Order No. 25,970 at 4-5 (December 7, 2016. A successful motion must establish "good reason" by showing that there are matters that the Commission "overlooked or mistakenly conceived in the original decision," *Dumais v. State*, 118 N.H. 309, 311 (1978) (quotation and citations omitted), or by presenting new evidence that was "unavailable prior to the issuance of the underlying decision," *Hollis Telephone Inc.*, Order No. 25,088 at 14 (April 2, 2010). A successful motion for rehearing must do more than merely restate prior arguments and ask for a different outcome. *Public Service Co. of N.H.*, Order No. 25,970, at 4-5 (citing *Public Service Co. of N.H.*, Order No. 25,676 at 3 (June 12, 2014); *Freedom Energy Logistics*, Order No. 25,810 at 4 (September 8, 2015)).

B. Issues for Rehearing

i. Pemigewasset Substation

Eversource first argues that the Commission erred in finding the $911,000 in costs incurred resolving the engineering flaw in its Pemigewasset Substation Project were imprudent because "it never specified the particular basis for its conclusion." Mot. for Reh'g at 6 ¶ 12. The Commission's order, however, identifies several facts providing ample support for the conclusion that the costs were imprudently incurred. Namely, Eversource's "contracts limit contractor liability, . . . [Eversource] did not seek any 'insurance' claim through the contractor for 'consequential' damages, and . . . [Eversource's] own internal reviews did not catch the issue." Order at 6. To the extent Eversource argues that the Commission should have weighed these facts differently and reached a contrary conclusion, such an argument cannot form the basis to grant rehearing. *See Public Service Co. of N.H.*, Order No. 25,970, at 4-5.

Eversource further argues that the Commission should grant rehearing because the Commission's order "does not define or explain what the standard of prudence is." Mot. for Reh'g at 7 ¶ 14. Eversource does not argue the Commission applied the wrong standard. Instead, it appears to argue that the Commission's failure to cite to a standard in its order requires rehearing. The prudence standard is, however, well established, as evidenced by the numerous Commission dockets and New Hampshire Supreme Court cases cited by Eversource. *Id.* To the extent the Commission erred by not citing to a case for the prudency standard, that error is harmless because the costs incurred were imprudent under the standard established by the cases Eversource cites. As is evident from the Commission's Order, the Commission does not fault Eversource for its contractor's errors. However, Eversource's imprudent contracting practices left it insufficiently insulated against its contractor's errors, incurring nearly $1 million in additional costs. The motion to reconsider the Commission's prudency finding on this issue is denied.

ii. Winnipesaukee Cable Replacement

Eversource's argument with respect to the Winnipesaukee cable replacement similarly fails because it amounts to another request that the Commission re-weigh the same evidence and reach a contrary conclusion. Although Eversource asserts that there is "no basis for the Commission's conclusion," Mot. for Reh'g at 10 ¶ 19; the Order, in fact, identifies the insufficient "underlying analysis and estimate regarding this project" was the basis for concluding that the costs were imprudently incurred, Order at 6. Eversource provides no new evidence nor identifies any error of law undermining the Commission's conclusion.

Energy's argument that the Commission should grant rehearing because "it is unclear from the record whether either of [Eversource's] estimates considered repair options rather than replacement," Resp. to Mot. for Reh'g at 4 ¶ 8, similarly fails. This assertion falls far short of identifying evidence that was overlooked, mistakenly conceived, or not available at the time of the original order. Energy observed in a footnote that the list provided by the Company of alternatives considered did not include cable repair options. If Energy had identified evidence in the record on the repair costs of the cable that the Commission had overlooked, that might form the basis to grant rehearing. But Energy has merely asserted the hypothetical existence of such evidence. Accordingly, Eversource's and Energy's requests for rehearing on the Winnipesaukee cable issue are both denied.

iii. LTCCs as Expense Item

Eversource argues the Commission should grant rehearing on its decision to treat LTCCs as an expense item, rather than a capital item, because Eversource did not have sufficient opportunity to be heard on that issue prior to the Commission reaching this determination. The Commission's decision to change the treatment of LTCCs was based upon the Step 1 audit report. Eversource had access to this report prior to the adjustment hearing and had the opportunity to respond to the recommendations contained therein. As noted in the Order, at the hearing, Eversource discussed its historical treatment of this expense as a maintenance expense. With its motion, Eversource has not identified any error of law or fact that the Commission overlooked or mistakenly conceived and instead merely disagrees with the Commission's Order regarding the audit recommendation. This cannot form the basis to grant rehearing and Eversource's motion is, accordingly, denied.

C. Issues for Clarification

To the extent necessary, the Commission now clarifies the following terms.

i. "Subject to reconciliation"

The Commission's use of the phrase "subject to reconciliation" is in reference to the amount included in the step adjustment the Department of Energy Audit Report concluded does not account for the anticipated contributions and the Department of Energy raised at hearing. *See* Exh. 63 at 6. As Eversource stated at hearing, this is an ongoing issue dating back to the first step adjustment in this matter that "could be resolved through or further understood through the business process audit." Hearing Transcript of 7/19/21 at 101. The Commission clarifies that while Order No. 26,504 found that Eversource may recover the identified amounts through distribution rates, because of the ongoing nature of the dispute over the treatment of those expenses and the Company's representation that it could be resolved through or further understood through the anticipated business process audit, such costs should be subject to reconciliation based on the outcome of the business process audit. The Commission clarifies that it will take the issue up upon a motion filed by a party based on the outcome of the business process audit as necessary, and after affording the parties all due process.

ii. "On a going forward basis"

The Commission's use of the phrase "on a going forward basis" means "as of the date of this order," namely, as of July 30, 2021.

Based upon the foregoing, it is hereby

ORDERED, that Eversource's motion for reconsideration is denied as to all issues; and it is

FURTHER ORDERED, that Energy's motion for reconsideration is likewise denied; and it is

FURTHER ORDERED, that the Commission's Order is clarified as explained in section C above.

By order of the Public Utilities Commission of New Hampshire this twenty-seventh day of September, 2021.

Dianne Martin Chairwoman	Daniel C. Goldner Commissioner

Service List - Docket Related

Docket# : 19-057

Printed: 9/27/2021

Email Addresses

ClerksOffice@puc.nh.gov
mbirchard@keyesfox.com
aboyd@acadiacenter.org
brianna@cleanenergynh.org
kelly@cleanenergynh.org
brian.d.buckley@energy.nh.gov
rburke@nhla.org
richard.t.chagnon@energy.nh.gov
jessica.chiavara@eversource.com
john@johncoffman.net
roger@fsconline.com
kristi.davie@eversource.com
allen.desbiens@eversource.com
paul.b.dexter@energy.nh.gov
jdonahue@preti.com
pearl.donohoo-vallett@brattle.com
jay.e.dudley@energy.nh.gov
stephen.r.eckberg@energy.nh.gov
eemerson@primmer.com
sam@cleanenergynh.org
matthew.fossum@eversource.com
thomas.c.frantz@energy.nh.gov
mhorne@hcc-law.com
tklaes@blueridgecs.com
donald.kreis@oca.nh.gov
erica.menard@eversource.com
karen.j.moran@energy.nh.gov
scott@sjmuellerlaw.com
dmullinax@blueridgecs.com
elizabeth.r.nixon@energy.nh.gov
amanda.o.noonan@energy.nh.gov
ocalitigation@oca.nh.gov
rebecca.ohler@des.nh.gov
rorie.e.patterson@energy.nh.gov
melissa.price@eversource.com
agustin.ros@brattle.com
sanem.sergici@brattle.com
christopher.skoglund@des.nh.gov

stower@nhla.org
jacqueline.m.trottier@energy.nh.gov
dvenora@keeganwerlin.com
david.k.wiesner@energy.nh.gov
jrw@psu.edu
craig.wright@des.nh.gov

Puc 203.25 **Burden and Standard of Proof**.

Unless otherwise specified by law, the party seeking relief through a petition, application, motion or complaint shall bear the burden of proving the truth of any factual proposition by a preponderance of the evidence.

Puc 1604.05 **Notice of Intent to File Rate Schedules.**

(a) Any utility intending to file a proposed rate schedule change pursuant to RSA 378 shall file with the commission and the New Hampshire office of consumer advocate written notice of its intent to file rate schedules at least 30 days prior to the actual filing of such schedules.

(b) The notice required by (a) above shall state the approximate amount of the proposed change in rates.

(c) Compliance with (a) and (b) above shall be deemed to have expired if the utility has not filed its proposed rate schedule with the commission by the earlier of the following:

(1) Within 60 days of the commission's receipt of the written notice required in (a) above; or

(2) If the commission has granted a utility's request for a waiver pursuant to Puc 201.05 of the 30 day notice requirement of (a) above and authorized it to file its proposed rate schedule earlier than 30 days, by the date established by such waiver.

(d) When a utility proposes that tariff revisions shall become effective on less than 30 days notice to customers, the utility shall submit a written request, which shall describe the reason for the request, for a waiver pursuant to Puc 201.05 for such authority.

363:17-b Final Orders. –

The commission shall issue a final order on all matters presented to it. Matters resolved by final order of the commission shall be exempt from RSA 541-A:29 and RSA 541-A:29-a, but shall be subject to federal and state time limitations applicable to specific matters. The transcript or minutes of oral deliberations shall not constitute a final order. A final order shall include, but not be limited to:

I. The identity of all parties;

II. The positions of each party on each issue;

III. A decision on each issue including the reasoning behind the decision; and

IV. The concurrence or dissent of each commissioner participating in the decision.

363:28 Office of the Consumer Advocate. –

I. The office of the consumer advocate shall be an independent agency administratively attached to the public utilities commission pursuant to RSA 21-G:10. The office shall consist of the following:
(a) A consumer advocate, appointed by the governor and council, who shall be a qualified attorney admitted to practice in this state. The consumer advocate shall serve a 4-year term and until a successor is appointed and qualified.
(b) An assistant consumer advocate appointed by the consumer advocate, who shall be a full-time classified employee.
(c) A secretary appointed by the consumer advocate.
(d) Two additional staff people appointed by the consumer advocate. When filling these positions, the consumer advocate should consider appointing rate analysts or economists.
II. Except as pertains to any end user of an excepted local exchange carrier or services provided to such end user, the consumer advocate shall have the power and duty to petition for, initiate, appear or intervene in any proceeding concerning rates, charges, tariffs, and consumer services before any board, commission, agency, court, or regulatory body in which the interests of residential utility consumers are involved and to represent the interests of such residential utility consumers.
III. The consumer advocate shall have authority to contract for outside consultants within the limits of funds available to the office. With the approval of the fiscal committee of the general court and the governor and council, the office of the consumer advocate may employ experts to assist it in proceedings before the public utilities commission, and may pay them reasonable compensation. The public utilities commission shall charge a special assessment for any such amounts against any utility participating in such proceedings and shall provide for the timely recovery of such amounts for the affected utility.
IV. The consumer advocate shall have authority to promote and further consumer knowledge and education. The consumer advocate shall advocate against proposed regional or federal rules or policies that are inconsistent with the policies, rules, or laws of New Hampshire. In its participation in regional activities, the consumer advocate shall consider how other states' policies will impact New Hampshire rates and work to prevent or minimize any rate impact the consumer advocate determines to be unjust or unreasonable.
V. The consumer advocate shall publicize the Link-Up New Hampshire and Lifeline Telephone Assistance programs in order to increase public awareness and utilization of these programs.
VI. The filing party shall provide the consumer advocate with copies of all confidential information filed with the public utilities commission in adjudicative proceedings in which the consumer advocate is a participating party and the consumer advocate shall maintain the confidentiality of such information.

378:6 Suspension of Schedule. –

I. (a) Pending any investigation of a rate schedule which represents a general increase in rates and the decision thereon, the commission may, by an order served upon the public utility affected, suspend the taking effect of said schedule and forbid the demanding or collecting of the rates, fares, charges or prices covered by the schedule for such period or periods, not to exceed 12 months in all, as in the judgment of the commission may be necessary for such investigation, except as provided in paragraph II.
(b) Except as provided in RSA 378:6, IV, for all other schedules filed with the commission, the commission may, by an order served upon the public utility affected, suspend the taking effect of said schedule and forbid the demanding or collecting of rates, fares, charges or prices covered by the schedule for such period or periods, not to exceed 3 months from the date of the order of suspension, but if the investigation cannot be concluded within a period of 3 months, the commission in its discretion and with reasonable explanation may extend the time of suspension for 5 additional months.
II. If a public utility submits a rate schedule which incorporates a newly completed generating facility into the rate base and the capital investment for the new facility exceeds 50 percent of the total capital investment of the public utility, the commission may suspend the schedule as provided in paragraph I, except that such suspension shall not exceed 18 months. The total capital investment of the public utility shall include the capital investment of the new facility. The commission may suspend a schedule under this paragraph only once in relation to each new facility.
III. If for any reason the commission is unable to make its determination prior to the expiration of 6 months from the originally proposed effective date of a rate schedule, the public utility affected may place the filed schedule of rates in effect, pending expiration of the appropriate suspension period, as provided in paragraph I or II, upon furnishing the commission with a bond in such form and with such sureties, if any, as the commission may determine. The bond and sureties, if any, shall secure the repayment to the customers of the public utility of the difference, if any, between the amounts collected under said schedule of rates and the schedule of rates determined by the commission to be just and reasonable.
IV. Any tariff for services filed for commission approval by a telephone utility, except a tariff reviewed pursuant to RSA 378:6, I(a), shall become effective as filed 30 days after filing, unless the commission amends or rejects the filing within the 30-day period. The commission may, in its discretion and with reasonable explanation, including an explanation of the likely areas of disagreement with the tariff, extend the time for its determination by up to 30 days. At its discretion, the commission may permit changes to existing tariffs to become effective in fewer than 30 days from the date of filing.

378:27 Temporary Rates. –

In any proceeding involving the rates of a public utility brought either upon motion of the commission or upon complaint, the commission may, after reasonable notice and hearing, if it be of the opinion that the public interest so requires, immediately fix, determine, and prescribe for the duration of said proceeding reasonable temporary rates; provided, however, that such temporary rates shall be sufficient to yield not less than a reasonable return on the cost of the property of the utility used and useful in the public service less accrued depreciation, as shown by the reports of the utility filed with the commission, unless there appears to be reasonable ground for questioning the figures in such reports.

541-A:1 Definitions. –

In this chapter:
I. "Adjudicative proceeding" means the procedure to be followed in contested cases, as set forth in RSA 541-A:31 through RSA 541-A:36.
II. "Agency" means each state board, commission, department, institution, officer, or any other state official or group, other than the legislature or the courts, authorized by law to make rules or to determine contested cases.
III. "Committee" means the joint legislative committee on administrative rules, unless the context clearly indicates otherwise.
IV. "Contested case" means a proceeding in which the legal rights, duties, or privileges of a party are required by law to be determined by an agency after notice and an opportunity for hearing.
V. "Declaratory ruling" means an agency ruling as to the specific applicability of any statutory provision or of any rule or order of the agency.
V-a. "Electronic document" means a document which complies with requirements prescribed by the director for filing under paragraph VI and established in the drafting and procedure manual under RSA 541-A:8. For electronic documents, a requirement during the rulemaking process for a signature accompanying the filing of an electronic document shall be met if such signature complies with the requirements of RSA 294-E.
VI. "File" means the actual receipt, by the director of legislative services, of a document required to be submitted during a rulemaking process established by this chapter, under the terms and in the format prescribed by the director. The term "file" shall also apply to any other response, submission, or written explanation required during a rulemaking process established by this chapter.
VI-a. "Final legislative action" means the defeat of a joint resolution sponsored by the legislative committee on administrative rules pursuant to RSA 541-A:13, VII(b) in either the house or the senate, or the failure of the general court to override the governor's veto of the joint resolution.
VII. "Fiscal impact statement" means a statement prepared by the legislative budget assistant, using data supplied by the rulemaking agency, and giving consideration to both short- and long-term fiscal consequences and includes the elements required by RSA 541-A:5, IV.
VII-a. "Form" means a document that establishes a requirement for persons outside the agency to provide information to an agency and the format in which such information must be submitted. The term does not include any document, regardless of what the document is called, that (a) is provided by an agency to facilitate the submission of information that is required to be submitted to the agency by federal or state statute, regulation, or rule and does not add to or modify such requirement or (b) that is used only by the agency to provide information to persons outside the agency.
VII-b. "Internet content" means material that exists only on a website on the Internet.
VIII. "License" means the whole or part of any agency permit, certificate, approval, registration, charter or similar form of permission required by law.
IX. "Licensing" means the agency process relative to the issuance, denial, renewal, revocation, suspension, annulment, withdrawal or amendment of a license, or the imposition of terms for the exercise of a license.
X. "Nonadjudicative processes" means all agency procedures and actions other than an

adjudicative proceeding.

XI. "Order" means the whole or part of an agency's final disposition of a matter, other than a rule, but does not include an agency's decision to initiate, postpone, investigate or process any matter, or to issue a complaint or citation.

XII. "Party" means each person or agency named or admitted as a party, or properly seeking and entitled as a right to be admitted as a party.

XIII. "Person" means any individual, partnership, corporation, association, governmental subdivision, or public or private organization of any character other than an agency.

XIV. "Presiding officer" means that individual to whom the agency has delegated the authority to preside over a proceeding, if any; otherwise it shall mean the head of the agency.

XV. "Rule" means each regulation, standard, form as defined in paragraph VII-a, or other statement of general applicability adopted by an agency to (a) implement, interpret, or make specific a statute enforced or administered by such agency or (b) prescribe or interpret an agency policy, procedure or practice requirement binding on persons outside the agency, whether members of the general public or personnel in other agencies. The term does not include (a) internal memoranda which set policy applicable only to its own employees and which do not affect private rights or change the substance of rules binding upon the public, (b) informational pamphlets, letters, or other explanatory material which refer to a statute or rule without affecting its substance or interpretation, (c) personnel records relating to the hiring, dismissal, promotion, or compensation of any public employee, or the disciplining of such employee, or the investigating of any charges against such employee, or (d) declaratory rulings. The term "rule" shall include rules adopted by the director of personnel, department of administrative services, relative to the state employee personnel system. Notwithstanding the requirements of RSA 21-I:14, the term "rule" shall not include the manual described in RSA 21-I:14, I or the standards for the format, content, and style of agency annual and biennial reports described in RSA 21-I:14, IX, which together comprise the manual commonly known as the administrative services manual of procedures. The manual shall be subject to the approval of governor and council.

XVI. "Standing policy committee" means a committee listed in rules of the house of representatives or the senate to which legislation including rulemaking authority was originally referred for hearing and report.

77 N.H. P.U.C. 268, 1992 WL 511300 (N.H.P.U.C.)

Re Public Service Company of New Hampshire

DR 92-050
Order No. 20,503

New Hampshire Public Utilities Commission

June 5, 1992

Appearances: Gerald M. Eaton, Esq. for Public Service Company of New Hampshire; Rath, Young, Pignatelli and Oyer by William F. Ardinger, Esq. and Day, Berry and Howard by Robert P. Knickerbocker, Esq. and Gerald Garfield, Esq. for Northeast Utilities Service Company; Shelley A. Nelkens, *pro se*; Representative Mary C. Chambers (limited intervenor); Campaign for Ratepayers Rights (limited intervenor) by Robert C. Cushing, Jr.; Business and Industry Association (limited intervenor) by Kenneth Colburn; Michael W. Holmes, Esq. and Joseph W. Rogers, Esq. of the Office of the Consumer Advocate on behalf of residential ratepayers; James T. Rodier, Esq. on behalf of the Commission Staff.

Before Douglas L. Patch, Chairman, Bruce B. Ellsworth, Commissioner, Linda G. Bisson, Commissioner.

BY THE COMMISSION:

REPORT

I. PROCEDURAL HISTORY.

On March 18, 1992, Public Service Company of New Hampshire (PSNH)

filed a request for a hearing on the Fuel and Purchased Power Adjustment Clause (FPPAC) for the period from June 1, 1992, through November 30, 1992. An Order of Notice set a prehearing conference for April 9, 1992. (March 25, 1992). At the prehearing conference, the New Hampshire Public Utilities Commission (commission) granted intervention to Northeast Utilities Service Company (NUSCO), Business and Industry Association (BIA) and Shelley Nelkens. Tr. April 9, 1992 at 6. On March 16, 1992, PSNH submitted a Stipulation and Recommendations on Procedure and Scope. The commission adopted the Stipulation, set a technical conference for May 1, 1992, and scheduled the hearing to be held May 5 through 8, 1992. Report and Order No. 20,444 (April 20, 1992). The hearing was held on May 6 through 8, 1992, with the Seabrook outages issues to be continued at a later undetermined date.

On April 23, 1992, PSNH filed a Motion for Protective Order pertaining to Staff Data Request No. 68 which the commission subsequently granted. Report and Order No. 20,460 (April 27, 1992).

On May 22, 1992, PSNH submitted a letter to the commission identifying those issues that were either uncontested or would be deferred for late briefing. This letter has been attached hereto as Attachment 1.

On May 27, 1992, PSNH, Staff and OCA filed briefs containing their respective positions and arguments on the four contested issues in this proceeding.

II. SCOPE OF THE PROCEEDING.

The scope of this proceeding is to establish an FPPAC rate for effect from June 1, 1992 through November 30, 1992. PSNH is proposing an FPPAC rate of 0.000 ¢/Kwh for that period. PSNH filed a document entitled “Stipulation and Recommendations on Procedure and Scope” with the commission on March 16, 1992. The Stipulation, noted *supra,* was adopted by the commission on April 20, 1992, and provided that the currently-effective FPPAC rate remain in effect through May 31, 1992; and that a new FPPAC rate will be implemented on a bills-rendered basis as of June 1, 1992.

This proceeding will also include an examination and reconciliation of actual FPPAC costs for the period from May 16, 1991, through January 31, 1992.

III. POSITIONS OF THE PARTIES AND STAFF.

As noted *supra,* there are four issues which have been contested in this proceeding.

A. Trigger Mechanism

1. Staff and OCA

Staff and OCA argue that PSNH should have acted sooner in informing the parties as to the growth and magnitude of PSNH's over collection from ratepayers. FPPAC should not be used for the purposes of a short-term loan to PSNH at a prime interest rate when customers are borrowing at double digit rates of interest. The trigger mechanism needs to provide a meaningful opportunity for the parties to request interim changes. OCA also proposes that PSNH be penalized in the amount of $10,000 for its unreasonable conduct.

Staff and OCA recommend that the commission order the parties to consult on this matter and report to the commission within 30 days on a mechanism that will ensure that such huge overrecoveries/underrecoveries will not occur in the future.

2. PSNH

PSNH argues that the magnitude and rate of growth of the swap savings were unanticipated. The fact that the trigger threshold had been exceeded was not fully known to PSNH's personnel responsible for FPPAC until such time as estimates and calculations were being made for this FPPAC filing. PSNH is prepared to consult with Staff and other parties to ensure that an update of estimated data will be provided in a monthly FPPAC data filing. This update will provide an opportunity for an interim review and correction, if required, in the future.

B. Swap with Boston Edison Company

1. Staff and OCA

Staff and OCA argue that PSNH should have taken more vigilant action to ensure that the benefits of the swap with Boston Edison Company (BECo), as originally anticipated, were realized.

2. PSNH

PSNH and NUSCO argue that the agreement provided no guarantee of savings, only an opportunity, and that PSNH was prudent to revise the agreement and obtain all the energy from BECo during Seabrook's outage when it had the most value to PSNH.

C. Central Vermont Public Service Energy Penalty

1. Staff and OCA

Staff and OCA argue that PSNH should have anticipated the existence of a swap with Northeast Utilities (NU) at the time when the Newington sale was made and factored that element into the arrangements with Central Vermont Public Service (CVPS). The results of the sale ought to be restated to exclude any energy penalty resulting from the sale.

2. PSNH

PSNH argues that the Newington sale was made before the swap was consummated. It should be analyzed based upon the information available when the sale was made, rather than after the fact. The effects of the swap must be excluded when analyzing the results of the Newington sale to CVPS.

D. PSNH/NU Swap

1. Staff and OCA

Staff and OCA argue that the commission stated, in its final decision in the last FPPAC proceeding, that PSNH must show quantitatively that it optimized its relationship with NU including maximizing the swap savings and its share of the swap savings, and that no other markets were available for PSNH base load energy sales which would have been more attractive than the swap. All savings from the PSNH/NU swap ought to be divided between PSNH and NU based upon attribution to the generating stations that produced the savings. PSNH should have had a swap in effect for the full month of October, 1991. PSNH should also have exchanged more megawatts of Seabrook entitlement during August, 1991.

2. PSNH

PSNH argues that PSNH met its burden of showing that PSNH and NU maximized the possible savings available to the companies prior to merger. Section 4 of the Rate Agreement does not require PSNH and NU to create an exact facsimile of the Sharing Agreement prior to merger, just use their best efforts at achieving as much energy savings through an energy exchange agreement, i.e. energy swaps. Imitating the Sharing Agreement is not possible under NEPOOL rules prior to merger; furthermore, all sales and purchases of capacity by both companies should be taken into account. The Management Services Agreement suggests that an equal split of the savings was reasonable in the current energy and capacity market.

According to PSNH, PSNH and NU were restructuring the swap arrangements in October, 1991, and could not come to agreement on a monthly continuation of the swap. PSNH did not have much exposure at this time, and PSNH mitigated the lack of a swap with daily transactions. PSNH had set up an optimal swap for August, 1991, contingent upon Newington being in service. When Newington went out of service, PSNH saved the swap by offering Seabrook outage service.

IV. APPLICABLE LEGAL STANDARDS.

The New Hampshire General Court granted the commission authority to determine rates based upon what is “just and reasonable.” RSA 378:7. Case law provides guidance for interpreting this broad standard. When a utility has exhibited inefficiency, improvidence, economic waste, abuse of discretion, or action inimical to the public interest, costs incurred may not be passed on to ratepayers. *Appeal of Seacoast Anti-Pollution League,* 125 N.H. 708 (1985). The prudence standard is one of the specific standards that has been developed by the Court to govern the inclusion or exclusion of costs for ratemaking purposes. *Appeal of Conservation Law Foundation,* 127 N.H. 606, 637 (1986).

Prudence is “essentially an analogue of the common law negligence standard”. *Id*. “While the scope of the prudence principle is by no means clear, it at least requires the exclusion from rate base of costs that should have been foreseen as wasteful.” *Id*. “[P]rudence judges an investment or expenditure in the light of what due care required at the time an investment or expenditure was planned and made. *Id*. at 638.

The test of due care asks what a reasonable person would do under the circumstances existing at the time of a decision. *Fitzpatrick v. Public Service Co. of N.H.,* 101 N.H. 35 (1957). Stated differently, a lack of due care is the failure to use that degree of care that the ordinary reasonably careful and prudent person would use under like circumstances. 57A Am. Jur. 2d Negligence § 7 (1989).

One of the factors relevant to determination of reasonable care under the circumstances is special skill or knowledge:

One who engages in a business, occupation, or profession must exercise the requisite degree of learning, skill, and ability of that calling with reasonable and ordinary care; furthermore, the specialist within a profession may be held to a standard of care greater than that required of the general practitioner.

***Id.* at § 190.**

Consequently, it is the commission's responsibility and obligation under the law to determine whether PSNH conducted itself with the ordinary and reasonable level of care expected of highly trained and compensated specialists with regard to the four contested issues in this proceeding.

V. COMMISSION ANALYSIS.

We now turn to our analysis and findings with respect to the four contested issues in this proceeding.

A. Trigger Mechanism

All parties and staff agree and we are persuaded that the current mechanism does not work well. Accordingly, we direct staff and parties to meet and discuss the problem and present to the commission within 30 days of the date of this order a joint recommendation or, if unable to agree on one recommendation, a series of individual recommendations for an improved mechanism.

B. Boston Edison Swap

During the period which is subject to reconciliation in this proceeding, PSNH entered into a transaction with Boston Edison Company, described by PSNH in the following manner:

PSNH sold Seabrook to BECo during Pilgrim's outage during May through mid July 1991. BECo was to have returned a like amount of energy to PSNH during Seabrook's outage in late July through early October. The energy was to have come from Pilgrim and BECo's share of Millstone 3. Unfortunately, Pilgrim was late returning from its outage and Millstone 3 went off line unexpectedly just prior to the start of Seabrook's outage. BECo followed through on the obligation to return power to PSNH, but they were not able to deliver from Pilgrim until later in the period than originally planned and the balance of the energy was delivered from BECo System Power. *PSNH realized only about one tenth of its expected savings because the energy was not returned at the most optimal times*. (Emphasis added).

Exhibit No. 19 at 11.

We agree with Staff's position that PSNH did not demonstrate that it undertook reasonable efforts to ensure that the return of energy from the BECo swap would be at comparable value. We are particularly persuaded by the testimony of Ms. Wood as to the intent and meaning of the contract with BECo:

What we're saying is that the energy was expected to have a certain value to Public Service during Seabrook's outage and if for some reason BECo can't return that energy during the Seabrook outage, then *the intent is to try to schedule the return of that energy in a period that would have comparable value for Public Service to the period when Seabrook was out*.

Tr. May 6, 1992 at 135.

Our attention is drawn to the words “comparable value”, and it is clear from the record that no such value resulted from the swap in this instance. The sequence of events leading up to the swap, in fact, leads us to question whether or not the swapping mechanism, as used in this instance, is a prudent negotiating tool. From the initiating party's viewpoint, it probably is, since that party is aware of an imminent shut-down and is aware of the likelihood of availability of the swapping partner's capacity. The passing of time before the returned capacity is claimed, however, reduces the likelihood that the expected capacity will be available, and therefore reduces the likelihood that the expected comparable savings will be achieved.

The instant case exemplifies the problem. BECo and PSNH negotiated the swap in late April, just one week before BECo's Pilgrim plant went off line. The return of the swapped capacity from BECo, however, was to occur four months after the negotiations — a length of time which, at best, increased the possibility of the unavailability of BECo's plants for replacement power.

PSNH testified that it was only due to their extraordinary efforts that even $100,000 of offsetting power was received. We are persuaded by the record that there were other measures that they could have taken to obtain a more advantageous power mix and which would have reached a more “comparable value” than was achieved. If we accepted that such were not the case, however, and we accepted that PSNH had done all it should have done to reach “comparable value”, then we would be inclined to investigate whether the mechanism by which swaps occur is prudent, and whether such swaps should be disallowed unless provisions were added to assure that comparable value is assured.

We find that the record does not support a conclusion that PSNH used its best efforts to ensure that the swap would achieve comparable value, and therefore, we will not allow recovery of the $900,000 in additional costs which should have been avoided.

C. Newington/Central Vermont Energy Penalty

PSNH indicated, in its prefiled testimony, that it had

negotiated a sale of 7 MW of Newington to Central Vermont Public Service for the months of December, 1991, and January and February, 1992. CVPS was motivated by a need for reasonably priced energy; they didn't particularly need the capacity.

Exhibit No. 19 at 11, 12.

In this proceeding, an issue was raised by staff as to whether there was any incremental energy (i.e. an “energy penalty”) cost flowing through FPPAC as a result of the sale by PSNH of 7 MW from Newington to CVPS.

During cross-examination, PSNH testified as follows:

If we had committed to the swaps with Northeast Utilities that we did commit to prior to making this sale to Central Vermont Public Service, in all likelihood we would have seen an energy penalty. At the time I made the commitment to Central Vermont Public Service, I was aware that there was a high likelihood that we would have a swap in place with Northeast Utilities

Tr. May 6, 1992 at 145-147.

In essence, PSNH appears to contend that, because the Newington sale was made before the swap with NU was consummated, even though a swap was a "high likelihood", they should be allowed to pocket all of the capacity-related revenue received from CVPS and should not have to offset any energy penalty that will be visited on its ratepayers. We disagree.

The sale to CVPS might have been a prudent decision if it had been made in the absence of any negotiations with other utilities which would materially affect the economics of the sale to CVPS. In the instant case, however, the company knew there was a "high likelihood" of a pending NU swap which would, if it occurred, incur energy penalties. The record provides no insight as to whether or not there were economic advantages to the company and its customers which resulted from the sale even after consideration of the energy penalty. If there had been, we might view the prudency of this transaction differently. The record reveals no such advantages, however. We find, therefore, that PSNH did not give adequate consideration to the risk that the energy penalties would be imposed, and we will not allow them to impose those penalties on to their customers.

We will require PSNH to credit to FPPAC a portion of the capacity- related revenue it would otherwise retain as income sufficient to offset the "energy penalty" on its customers including any impact on the NU/PSNH swap savings.

D. NU/PSNH Swap

There are three sets of transactions between PSNH and NU at issue: a swap with NU in August 1991; a swap with NU in October, 1991; and a series of transactions with NU and third parties during the FPPAC reconciliation period.

Contrary to the urgings of Staff and other parties, we do not find evidence that PSNH was in error in contracting for the August, 1991, swap with NU during the period in which Newington Station and Seabrook were out of service.

The August, 1991 swap provided NU with an entitlement of 270 megawatts from PSNH's Newington Station. The agreement allowed NU to suspend the swap if Newington went out of service, evidencing the importance to NU of Newington as part of the mix of swapped units. *Id*. at 119. When Newington did go out of service, instead of allowing NU to suspend the swap, PSNH reformed the agreement and offered NU Seabrook scheduled outage service and took back NU combustion turbines which were more expensive on NU's system. PSNH made this change to the agreement at little or no cost, and the remaining benefits of the swap were rescued for PSNH's customers.

Similarly, we find no evidence that PSNH was in error in contracting for the October, 1991 swap with NU.

Seabrook's availability has a substantial impact upon the economics of the PSNH system. During the early autumn of 1991, PSNH and NU were discussing ways of adjusting swaps after Seabrook completed its refueling and returned to service. The September swap was merely continued during this period. Tr. May 6, 1992 at 110- 111. In October, 1991, PSNH and NU were attempting to restructure the swap arrangements and could not come to agreement on sharing the risk of unit availability, particularly for the large nuclear units on both systems. *Id*. Prior to October, 1991, PSNH and NU were adjusting the monthly swap agreements based upon the actual availability of large base load nuclear units and, as noted earlier, the process evolved to longer-term swaps based on projected data. The new swap began on November 1, 1991, after the arms-length negotiations over availability risk were resolved. A portion of the October swap became a victim of that negotiation process. *Id*. at 113-114.

We now turn to the principal issue in this proceeding which involves the sharing of swap savings prior to merger.

Mr. Staszowski, PSNH's director of power supply, discussed the capacity swaps between PSNH and NU which were in effect for the period July, 1991, through April, 1992. These capacity swaps were designed to realize, prior to merger, some of the combined system energy savings which will be created by the PSNH/NU merger. They account for the majority, in dollar volume and energy, of PSNH's power contracting business in this period. Exhibit 19 at 2.

According to Mr. Staszowski,

The objective of the swap capacity between two utilities is to increase or to create savings that aren't otherwise present on this system by swapping units on one system which has less value than the units have on the other person's system. By reducing the size of the units such that they operate more efficiently in the on-load dispatch.

Tr. May 6, 1992 at 77.

Under cross-examination, Mr. Staszowski agreed that PSNH typically transferred 700 MW of its generating capacity to NU, which is about 40 percent of its total resources. *Id*. at 78. During the current period, PSNH received in excess of $80 million in revenue from the sale of over four billion kilowatt hours to NU. *Id*. at 80.

During the cross-examination of Mr. Staszowski, as noted in staff's brief, the essence of the swap reduced to the following description:

Q Okay. Basically what I think they're saying is that, with Seabrook in service, Public Service has an awful lot of base load energy to get rid of out-of-state, is that correct?

A We have more base load capacity than we need for our load curve.

Q Okay. Well, if you're selling six million to people in the state and four out-of-state, I mean, I would say that's substantial, wouldn't you?

A Yes, I would.

Q Okay. And can we agree that the lion share of this energy going out-of-state is going to NU?

A Yes.

***Id.* at 89.**

Moreover, if PSNH surplus power is sold off the combined system after the merger, PSNH will get the lion's share of the benefit as confirmed in the following exchange during cross examination:

Q. In any event, I think we agreed that NU will call the shots on, if there is a sale of Public Service surplus power, NU will call the shots on it and if Seabrook is running, Public Service will get the lion's share of the benefit back, is that correct?

A. If PSNH creates the savings, PSNH will get the lion's share of the benefit.

***Id*. at 107.**

It also became readily apparent during cross-examination that there was no good reason why PSNH should not have received the lion's share of the benefits generated by the current swap prior to the merger:

Q. What I'm wondering is there anything that you know of that would prevent NU from giving back to Public Service more than fifty percent of the savings that PSNH creates on the NU system?

A. John Ash. Northeast Utilities would, in all likelihood, not agree to a swap that did not divide the savings 50/50. *I've asked*.

Q. Okay.

A. The level is proportioned to vary, but in their favor.

Q. The simple fact of the matter is, they wouldn't agree to give you back more than fifty percent of the savings you created?

A. That's correct.

Tr. May 6, 1992 at 172. (Emphasis added.)

PSNH argued strenuously that the Rate Agreement provides for an even division of energy savings between the NU and PSNH systems and requires a “best effort” to achieve as much of the expected energy savings as possible before the merger through energy exchange contracts. In the last FPPAC proceeding, the commission categorically rejected this position and admonished PSNH as follows:

PSNH has the burden of demonstrating that its ratepayers are obtaining the maximum benefits possible from the sale of PSNH's surplus capacity. In subsequent proceedings, we will require PSNH to demonstrate quantitatively that not only has it optimized its contractual arrangements with NUSCO, but that it has also ascertained that other possible markets for the sale of the surplus power would not be as productive and profitable for PSNH ratepayers as selling the surplus to NUSCO.

Report and Order No. 20,475 (October 25, 1991) at 17.

The record does not clearly delineate the full details of the final category of transactions, and thus, we cannot yet rule on the prudency of those arrangements. We are not persuaded, however, by PSNH/NU's arguments that the savings of any pre-merger swaps or sales be shared on an equal 50/50 basis between PSNH and NU. Our concerns are heightened by Ms. Wood's own apparent attempt to garner more than 50 per cent of the savings. We are inclined to believe that since the full benefits were provided by PSNH and prior to the merger, those benefits should accrue to PSNH's ratepayers. We recognize, however, that NU, upon further record development of these transactions, may persuade us that some portion of the savings should accrue to NU. We are not able on the basis of this record now before us, however, to determine what, if any, sharing mechanism is appropriate.

In its brief, OCA expressed an additional concern pertaining to the PSNH/NU swap,

Through cross-examination, record request 4, and a clarification to said record request, the OCA sought to learn if NU was making off- system sales (energy or capacity) and retaining 100% of those sales margins, while concurrently receiving PSNH power (sales or capacity) through the swap to meet NU's retail needs, while also receiving 50% of PSNH's generated savings.

OCA Brief at 5-6.

OCA has requested the commission to defer ruling on this issue until further investigation and discovery can take place.

Clearly, another hearing is necessary to present full evidence on all of the swap-related transactions on the record. We ask PSNH to quantify each transaction in greater detail, providing us with the amount of energy in question, the cost, and with whom the transaction occurred, as we believe it may be relevant to distinguish between swaps with NU and sales to third parties. [1] We suggest the matter be addressed in conjunction with the Seabrook outage issues deferred until June 25, 1992. Of course, if PSNH is not able to present evidence on the questions we have identified by that date, we ask PSNH to consult with the Staff and parties to determine a mutually agreeable hearing date for this issue.

E. Conclusion

As noted *supra,* PSNH has proposed an FPPAC rate of 0.000 ¢/Kwh. Although the foregoing analysis and findings will likely result in a substantial disallowance of cost recovery for PSNH, it is nevertheless just and reasonable to approve PSNH's proposed FPPAC rate of 0.000 ¢/Kwh. Mr. Hall of PSNH quite accurately summarized in simple terms how Paragraph B.K. of FPPAC works under current circumstances:

As a result of that increased over-recovery, which we then incorporated into the calculation of the rate in effect from June through November '92 that increased over-recovery resulted in a negative FPPAC rate even with recovering all of the Cooperative's cost. Now under that scenario, what we did in response to the data request is we didn't file calculations showing a negative FPPAC rate. Rather, we filed calculations again showing an FPPAC rate of zero. *The way we got from a negative FPPAC rate up to a rate of zero was to assume that we would begin amortizing some of the previously deferred Cooperative cost in a sufficient amount to eliminate the negative FPPAC rate and bring the rate to zero*.

Tr. May 6, 1992 at 13 (Emphasis added).

Stated differently, it is necessary to decouple PSNH's proposed FPPAC from its current level of prudent cost recovery. Even though the ultimate level of prudent cost recovery allowed by the commission will be less than the BA reference level contained in FPPAC, PSNH is entitled under Paragraph B.K., to bill an FPPAC rate 0.000 ¢/Kwh rather than a negative FPPAC rate (i.e., a bill credit). This will allow PSNH to recover some of the FPPAC costs that have been deferred for future recovery, thereby benefitting customers over the long run.

Our order will issue accordingly. Concurring: June 5, 1992

Douglas L. Patch, Chairman, Bruce B. Ellsworth, Commissioner, Linda G. Bisson, Commissioner.

DR 92-050PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE Fuel and Purchased Power Adjustment Clause Order Approving in Part and Denying In Part Fuel and Purchased Power Adjustment Clause Charges Order No. 20,503

Upon consideration of the foregoing report which is made a part hereof; it is hereby

ORDERED, that PSNH's proposed FPPAC rate of 0.000 cents per kilowatt hour is approved for all bills rendered on or after June 1, 1992, until November 31, 1992; and it is

FURTHER ORDERED, that PSNH shall recalculate their recoverable FPPAC costs in a manner consistent with the foregoing report and any further report and order issued by this commission subsequent to completion of the record in this proceeding; and it is

FURTHER ORDERED, that PSNH's proposed rates for small power producers (Exhibit 15) are approved.

By order of the Public Utilities Commission of New Hampshire this fifth day of June, 1992.

Douglas L. Patch, Chairman, Bruce B. Ellsworth, Commissioner, Linda G. Bisson, Commissioner.

Attested by:

Wynn E. Arnold Executive Director & Secretary

Footnotes

1 PSNH very recently reported the following information to the Securities and Exchange Commission:

Revenues for the quarter ended March 31, 1992 include $53.7 million in short-term power sales, of which $47.8 million was sold to NU, compared to $32.2 million in total short-term power sales, of which $29.6 million was sold to NU, for the same period in 1991. The significant increase in short term sales to NU is primarily due to a decrease in the availability of NU system capacity, since NU's Millstone units were out of service at various points during the period.

PSNH Form 10-Q at 20 (May 14, 1992).

End of Document

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DE 11-250

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Investigation of Scrubber Costs and Cost Recovery

Order Denying Third Motion for Rehearing

O R D E R N O. 25,565

August 27, 2013

I. PROCEDURAL HISTORY

This docket considers the prudence of the costs and cost recovery for the wet flue gas desulfurization system (Scrubber) installed by Public Service Company of New Hampshire (PSNH) at its coal-fired generation plant known as Merrimack Station. PSNH installed the Scrubber pursuant to RSA 125-O:11-18 (the Scrubber law) which became effective June 8, 2006. The Office of Consumer Advocate (OCA), the New England Power Generators Association, Inc. (NEPGA), Jim and Sandy Dannis, TransCanada Power Marketing Ltd and TransCanada Hydro Northeast, Inc. (collectively, TransCanada), and Sierra Club and Conservation Law Foundation (jointly, SC/CLF) are all parties to this docket.[1]

In connection with discovery disputes that arose in this docket, the Commission gave parties the opportunity to file legal briefs "regarding their views of the proper interpretation of RSA 125-O:10, RSA 125-O:17 and the cost recovery provisions of RSA 125-O:18, and how these statutes relate to one another, to the application of the standard for discovery of evidence, and to relevance." Order No. 25,398 (August 7, 2012) at 10.

[1] Detailed procedural histories can be found in Order No. 25,332 (February 6, 2012), Order No. 25,346 (April 10, 2012), Order No. 25,298 (August 7, 2012), Order No. 25,506 (May 9, 2013) and Order No. 25,546 (July 15, 2013). All documents filed in DE 11-250 can be found on the Commission's website at http://www.puc.nh.gov/Regulatory/Docketbk/2011/11-250.html.

PSNH, TransCanada, SC/CLF, and the OCA filed briefs on August 28, 2012. On December 24, 2012, the Commission issued Order No. 25,445 (Discovery Order) in which the Commission ruled on the outstanding discovery motions and construed the above-referenced statutory provisions of RSA 125-O. In particular, the Commission reasoned that PSNH "could have requested a variance from the 80% reduction requirement, and could have sought a lesser level of reduction, even down to no reduction at Merrimack Station, while pursuing a request to retire Merrimack Station. Retirement of Merrimack Station would effectively eliminate all emissions from the station and leave only continued emissions from PSNH's other generation units, reducing PSNH's overall mercury emissions significantly." Order No. 25,445 at 25.

PSNH timely filed a motion for rehearing of Order No. 25,445 (First Rehearing Motion) on January 23, 2013, to which TransCanada, SC/CLF, and the OCA objected. PSNH pointed out an apparent inconsistency between our reasoning in Order No. 25,445 and a prior order, in which we stated that "[n]owhere in RSA 125-O does the Legislature suggest that an alternative to installing scrubber technology as a means of mercury compliance may be considered, whether in the form of some other technology or retirement of the facility." *See* Order No. 24,898 at 12. On May 9, 2013, the Commission issued Order No. 25,506 (First Rehearing Order) granting in part PSNH's motion. We agreed with portions of PSNH's analysis regarding RSA 125-O:17 and concluded that: "we will not disturb the prior Commission ruling in Order No. 24, 898. To the extent that [the Discovery Order] interpreted the variance provision RSA 125-O:17, to allow retirement of Merrimack Station rather than installation of the scrubber technology as a method of meeting the emissions reduction requirements, that portion of Order No. 25,445 alone is reversed." First Rehearing Order at 17.

The OCA, TransCanada, and SC/CLF filed a Joint Motion for Rehearing, Clarification and/or Reconsideration (Second Rehearing Motion) of the First Rehearing Order on May 28, 2013. The movants argued that the Commission erred regarding its interpretation of RSA 125-O:17. PSNH filed an Objection to the Second Rehearing Motion on May 31, 2013.

On July 15, 2013, the Commission issued Order No. 25,546 (Second Rehearing Order). The Commission denied the substantive relief requested in the Second Rehearing Motion but clarified the scope of this proceeding. With regard to the scope of its prudence review, the Commission construed RSA 125-O:18, the cost recovery section of the Scrubber Law, and RSA 369-B:3-a, which governs PSNH's divestiture and retirement of Merrimack Station Second Rehearing Order at 7-10. The Commission concluded that PSNH retained the management discretion to divest itself of Merrimack Station under RSA 125-O:18 or to retire Merrimack Station under RSA 369-B:3-a, if appropriate. *Id.* at 8. We further ruled that "PSNH's prudent costs of complying with RSA 125-O must be judged in accordance with the management options available to it at the times it made its decisions to proceed with and to continue installation [of the Scrubber]." PSNH timely filed a motion for rehearing of the Second Rehearing Order on August 9, 2013 (Third Rehearing Motion). The OCA, TransCanada, and SC/CLF jointly filed an objection to the Third Rehearing Motion on August 16, 2013.

We deny rehearing.

II. POSITIONS OF THE PARTIES

A. Public Service Company of New Hampshire

PSNH made three broad arguments in its Third Rehearing Motion. First, PSNH argued that the Second Rehearing Order is inconsistent with prior orders of the Commission and with the provisions of RSA 125-O:11-18. Third Rehearing Motion at 5-13. Second, PSNH argued that the Commission's construction of RSA 125-O:18 conflicts with those portions of RSA 125-O that require installation of Scrubber technology, violates principles of statutory construction, creates illogical results and bad public policy, renders RSA 125-O:18 unconstitutional, and violates due process. *Id.* at 13-33. Third, PSNH argued that the Commission's construction of RSA 125-O:17 is erroneous, making the Second Rehearing Order inconsistent internally and with prior orders. *Id.* at 33-37. Where warranted, we address PSNH's more particularized arguments in our analysis below.

B. OCA, TransCanada, and SC/CLF

The OCA, TransCanada, and SC/CLF (Objecting Parties) argued that PSNH relied upon the same arguments it asserted in prior pleadings and therefore failed to meet the Commission's standard for granting rehearing. Objection to Third Rehearing Motion at 1-2 and 14. They argued that the Second Rehearing Order is consistent with statute, that the Third Rehearing Order is entirely consistent with Commission analyses in the instant and other dockets, and that PSNH ignored prior Commission orders in this docket and elsewhere regarding the Commission's authority to conduct prudence reviews. *Id*. at 5-7.

According to the Objecting Parties, accepting PSNH's analysis of RSA 125-O:18 would render the statute meaningless and contrary to principles of statutory construction, would make a mockery of the prudence review mandated by the statute and the Commission's authority to ensure that a utility's assets are used and useful, would restrict the Commission's traditional and fundamental authority to act as the arbiter between the interests of the customer and the interests of the regulated utility, and would restrict the Commission's authority to ensure that rates are just and reasonable; authority the Commission employs in order to protect ratepayers from the abuse of a monopoly. *Id*. at 3-4. The Objecting Parties stated that PSNH's argument ultimately fails because it does not recognize the scope and implications of a prudence review, which the Legislature expected the Commission to perform as evidenced by the enactment of RSA 125-O:18. *Id*. at 8.

Further, the Objecting Parties argued that PSNH's claim that it was denied due process by the "arbitrary decision-making" of the Commission strains credibility because PSNH was familiar with the law long before Scrubber costs were incurred, and PSNH knew of the Commission's plenary authority to review and oversee all activities of regulated utilities. According to the Objecting Parties, the Scrubber Law contains no provisions limiting Commission authority. *Id*. at 11.

III. COMMISSION ANALYSIS

A. Standard for Rehearing

Pursuant to RSA 541:3, the Commission may grant rehearing or reconsideration when a party states good reason for such relief and demonstrates that a decision is unlawful or unreasonable. *See Rural Telephone Companies*, Order No. 25,291 at 9, 96 NH PUC 646 (2011). Good reason may be shown by identifying specific matters that were "overlooked or mistakenly conceived" by the deciding tribunal, *see Dumais v. State*, 118 N.H. 309, 311 (1978), or by identifying new evidence that could not have been presented in the underlying proceeding, *see O'Loughlin v. N.H. Personnel Comm'n*, 117 N.H. 999, 1004 (1977), *Hollis Telephone, Inc., Kearsarge Telephone Co., Merrimack County Telephone Co., and Wilton Telephone Co.*, Order No. 25,088 (Apr. 2, 2010) at 14. A successful motion for rehearing does not merely reassert prior arguments and request a different outcome. *See Connecticut Valley Electric Co.*, Order No. 24,189, 88 NH PUC 355, 356 (2003), *Comcast Phone of New Hampshire*, Order No. 24,958 at 7, 94 NH PUC 166 (2009), and *Public Service Company of New Hampshire*, Order No. 25,168 (November 12, 2010) at 10.

PSNH has not presented new evidence, nor has PSNH identified specific matters that were overlooked or mistakenly conceived by the Commission. On the contrary, PSNH's arguments demonstrate a misunderstanding of RSA 125-O:11-18 and our prior orders, including the Second Rehearing Order. PSNH's misunderstanding stems from a number of faulty underlying assumptions.

B. Consistency with Prior Commission Orders and With Statute

In the Second Rehearing Order, our clarification of the scope of this proceeding included a determination that PSNH retained the management discretion and duty of prudence to consider divestiture of Merrimack Station under RSA 125-O:18 and RSA 369-B:3-a. Consequently, the Second Rehearing Order made clear that discovery and testimony on this issue would be permitted.

This recent clarification of the scope of this proceeding is consistent with our prior orders on the scope of the prudence review that PSNH would eventually be subject to under the Scrubber Law. We have emphasized PSNH's decision-making responsibilities from the outset of proceedings in Docket DE 08-103, *Investigation of PSNH's Installation of Scrubber Technology at Merrimack Station*. In that docket we decided that, pursuant to RSA 369-B:3-a, we could not pre-approve *PSNH's decision* to modify Merrimack Station by constructing the Scrubber. Order No. 24,914 (November 12, 2008) ("[In Order No. 24,898], we concluded that the Commission lacked the authority to conduct a public interest review, in the form of pre-approval, of *PSNH's decision to install scrubber technology.*"). *Emphasis supplied.* Further, we stated:

> RSA 125-O:17 constitutes a mechanism for PSNH to seek relief from the Department of Environmental Service (DES) in certain circumstances; it does not constitute authority for the Public Utilities Commission to determine in advance whether it is in the public interest for PSNH to install scrubber technology. RSA 125-O:17 [sic.], however, is pertinent to prudence. We found previously that we retained our authority to determine prudence, including "determining at a later time the costs of complying with the requirements of RSA 125-O:11-18 and the manner of recovery for prudent costs." We note here that although RSA 125-O:17 provides PSNH the option to request from DES a variance from the statutory mercury emissions reductions requirement for reasons of "technological or economic infeasibility," it does not provide the Commission authority to determine at this juncture whether PSNH may proceed with installing scrubber technology. RSA 125-O:17 [sic] does, however, provide a basis for the commission to consider, in the context of a later prudence review, arguments as to whether PSNH had been prudent in proceeding with installation of scrubber technology in light of increased cost estimates and additional costs from other reasonably foreseeable regulatory requirements such as those cited by the Commercial Ratepayers, which include the Clean Air Act, 42 U.S.C. §7401 et seq., and the Clean Water Act, 33 U.S.C. §1251 et seq.

Investigation of PSNH's Installation of Scrubber Technology, Order No. 24,914 at 13, 93 NH PUC 564 (2008). Although we note in reviewing Order No. 24,914 that prudence is more properly referred to in RSA 125-O:18 and not in RSA 125-O:17, the import of Docket DE 08-103 remains the same: No utility may proceed blindly with the management of its assets or act irrationally with ratepayer funds; PSNH had a duty to its ratepayers to consider the appropriate response, possibly even including a decision to no longer own and operate Merrimack Station, when facing changing circumstances.[2] As Order No. 24,914 made clear, the scope of our eventual prudence review would encompass those issues.

Despite the guideposts set in Docket DE 08-103, PSNH has confused our inability to address the public interest in reducing mercury emissions from operating coal plants, with Commission approval of PSNH's continued ownership and operation of Merrimack Station

[2] We were conscious that we had incorrectly referenced RSA 125-O:17 as the section relevant to prudence in Order 24,914 when we quoted that order on pages 8-9 of the Second Rehearing Order. This was the reason for our use of the Latin "Sic." in our quotations of Order 24,914. Consequently, PSNH's third argument is unfounded and does not merit discussion. *See* Third Rehearing Motion at 33-37.

regardless of any contingency or economic effects of PSNH's decision-making. Additionally, PSNH has confused and conflated the statutory mandates upon owners of affected sources in RSA 125-O with its independent choice to continue to own and operate Merrimack Station.

Our previous statements regarding RSA 125-O:11-18, however specific to PSNH, were occasioned by and framed in the context of *PSNH's decision to continue its ownership and operation of Merrimack Station.* Our statements were not a directive that PSNH continue to own and operate Merrimack Station; were not a legal determination that the Legislature required PSNH to continue to own and operate Merrimack Station between 2006 and July 2013; and were not a legal determination that PSNH was the only entity that could install Scrubber technology. From the outset of proceedings before this Commission, we have characterized PSNH as having made a decision to proceed with the Scrubber project. This is because RSA 125-O mandated that the owner of Merrimack Station and not PSNH in particular, install Scrubber technology. Although PSNH has chosen to continue to own and operate Merrimack Station, RSA 125-O:11-18 did not compel PSNH to do so from 2006 through July 2013. Indeed, as a matter of law, RSA 369-B:3-a explicitly permitted PSNH to divest its remaining generation assets, including Merrimack Station, beginning May 1, 2006, and no section of the Scrubber Law, RSA 125-O:11-18, altered PSNH's ability to do so.

Within the more than 100 pages of argument that PSNH has filed regarding the interpretation of RSA 125-O:11-18, PSNH has not identified any statutory basis for its argument that PSNH was required to continue its ownership of Merrimack Station. PSNH's argument in this regard is that, while plausible, a reading of RSA 125-O:18 that would have allowed PSNH to sell Merrimack Station prior to completion of a Scrubber installation is "impractical" and "illogical" and would lead to "absurd" results. PSNH argues that it was the only party with any reasonable and practical chance of complying with the seven-year timetable set by the Legislature for construction of a Scrubber. Third Rehearing Motion at 18-19. According to PSNH, a divestiture proceeding would have taken so long and the penalties for failing to install Scrubber technology at Merrimack Station by July 2013 were so severe that no new owner would have ever stepped forward. *Id.* at 19.

We considered whether such "practical" concerns made our interpretation of RSA 125-O:18 and RSA 369-B:3-a "illogical," but because we did not believe that the practical concerns led to an illogical or absurd result, we rejected them in favor of the plain wording of the statute. Fundamentally, the practical concerns now raised by PSNH are matters of fact that must be weighed and tested as part of the adjudicative process. These practical concerns are more relevant to whether PSNH acted prudently when it chose to continue to own and operate Merrimack Station and thus be obligated to meet the mercury reduction requirements, than to a statutory interpretation of the Scrubber Law.

Moreover, PSNH's practical concerns appear to be overstated. First, we note that it did not require seven years to complete the Scrubber project. As we found in the Discovery Order, the Scrubber was substantially completed and entered into service in September 2011, at least 19 months in advance of the July 2013 compliance deadline set by the Legislature. Order No. 25,445 at 24. Second, PSNH and the Commission have had recent experience with divestiture. *See* Docket No. DE 00-272 *Divestiture of NAEC/PSNH Electric Generation Facilities* and Docket No. DE 02-075 *PSNH, Sale of Seabrook Station Interests*, in which PSNH and a number of other parties accomplished the divestiture of Seabrook Station in less than two years from the signing of the Restructuring Settlement Agreement to Commission approval of the sale. In fact, in Docket No. DE 00-272, PSNH represented that the sale of fossil-fueled plants such as

Merrimack Station would only take 12 months from start to finish with some additional time for preparation and contingencies: "Experience in power plant divestitures through the Northeast indicates that such divestitures require approximately 12 months to conduct from launch to closing. There are many variables that make it difficult to accurately predict the actual process duration." PSNH bolstered this statement with three examples of sales taking 10, 12, and 13 months and represented "[t]hese experiences are typical of other asset divestitures in the Northeast." Public Service Company of New Hampshire: Nuclear, Fossil and Hydroelectric Asset Divestiture Plans, at 6, Docket No. DE 00-272, December 15, 2000 (on file with the NHPUC). Moreover, while we do not consider it determinative, PSNH and a new owner could have made the sale of Merrimack Station contingent upon receiving a variance from the July 2013 deadline from DES pursuant to RSA 125-O:17, II.[3]

Another of PSNH's concerns is that recovery of its prudently incurred costs could only be determined after the Scrubber was completed and the costs of compliance were known, effectively prohibiting PSNH from divesting Merrimack Station either prior to or during the construction of the Scrubber. *See, e.g.,* Third Rehearing Motion at 14-15, 17, and 25. We find no support for this argument in statute. Both RSA 125-O:18 and RSA 369-B:3-a require this Commission to allow recovery of prudently incurred costs of even partial compliance in the event of divestiture as neither statute requires that PSNH have owned Merrimack Station from the inception to the completion of the Scrubber project.

Notwithstanding PSNH's practical concerns, the plain wording of RSA 125-O:11-18 applies to the owner of Merrimack Station, not to PSNH specifically. Additionally, the plain

[3] Although the Commission rejects PSNH's concern regarding the duration of a sale as a basis for interpreting RSA 125-O:18 and RSA 369-B:3-a, the Commission does not here make a specific finding as to how long a sale of Merrimack Station may have taken, which may be relevant to the prudence of PSNH's decision making. The parties remain free to introduce evidence on this issue at hearing.

wording of RSA 125-O:18 and 369-B:3-a contemplate that PSNH might divest itself of the station prior to completing the Scrubber installation while requiring that this Commission still approve utility recovery of prudent costs of compliance with RSA 125-O:11-18. PSNH admitted nearly as much in its pleading, when it stated: "Each of the provisions (of RSA 125-O:7, 13, and 16) would apply regardless of the owner," Third Motion for Rehearing at 18, and "The statutory mandate to install and have operational Scrubber technology by July 2013 is unequivocal, regardless of who the 'owner' was." *Id.* at 19. We will not deviate from the plain wording of the statute and adopt PSNH's version of a "practical" reading, especially not here, where divestiture and recovery of costs of divestiture were contemplated by the statutory framework, the time that it would have taken to divest Merrimack Station was accommodated by a seven-year statutory compliance period, construction of the Scrubber did not take a full seven years, and there was the possibility of extending the seven-year compliance schedule by variance.[4]

Similarly, we considered and rejected failed legislation during the 2009 legislative session as helpful in interpreting RSA 125-O:18 and 369-B:3-a. The failure of Senate Bill 152 and House Bill 496 to pass their respective houses in 2009 tells us nothing of the meaning of RSA 125-O:11-18, enacted in 2006, or RSA 369-B:3-a, last amended in 2003. The demise of the 2009 bills may signal that the Legislature believed that the Commission already had the authority to review PSNH's decision-making in a prudence review, in which case the legislation would have been unnecessary, just as much as it may signal that, as argued by PSNH, the Legislature did not wish to provide the Commission with such authority. *See* Joint Objection to Third Motion for Rehearing at ¶5, fn.6 and Attachment B, which demonstrates that PSNH President

[4] Although the Commission rejects PSNH's practical concerns as bases for interpreting RSA 125-O:18 and RSA 369-B:3-a, we recognize that these concerns may be relevant to PSNH's prudence, an issue that will not be decided prior to hearing.

Gary Long assured the Senate that SB 152 was unnecessary because the Commission would conduct a normal, standard, after-the-fact prudence review to determine whether PSNH was "reckless" or "made bad decisions."[5]

C. RSA 125-O:18 and Divestiture

Our clarification that PSNH retained the management discretion and duty of prudence to consider divestiture of Merrimack Station under RSA 125-O:18 is not inconsistent with our prior construction of RSA 125-O and RSA 369-B:3-a. In Docket DE 08-103, we addressed the relationship between the Scrubber Law and RSA 369-B:3-a. In particular, we addressed whether, given the legislative mandate to install Scrubber technology, RSA 369-B:3-a nonetheless required us to pre-approve PSNH's decision to modify Merrimack Station. Our focus in that docket was not on prudence, divestiture or retirement, none of which were before us for consideration. *See* Order No. 24,898 at 12 (divestiture not before the Commission). We decided only that:

> . . . as a result of the Legislature's mandate *that the owner of Merrimack Station* install scrubber technology by a date certain, and its finding pursuant to RSA 125-O:11 that such installation of scrubber technology at PSNH's Merrimack Station is in the public interest of the citizens of New Hampshire and the customers of the station, the Commission lacks the authority to make a determination pursuant to RSA 369-B:3-a as to whether this particular modification is in the public interest.

Investigation of PSNH's Installation of Scrubber Technology, Order No. 24,898 at 13, 93 NH PUC 456 (2008) (*emphasis supplied).*

In coming to that construction of RSA 125-O and RSA 369-B:3-a, we determined in part that: "installation" of Scrubber technology at Merrimack Station and "modification" of

[5]See, e.g., Third Motion For Rehearing, Attachment B at 30-31 ("We have very detailed documents on [costs of ten elements of the project, the impact on rates, and the competitiveness of Merrimack Station to the market based on variations in fuel costs]. . . . We have very detailed documents on this. I mean the Public Utilities Commission can and will see all this stuff. They look at all these project things and they do a prudence review and they do a very thorough job. So we're not concerned with that, because we think we're doing a great job and we know they will do a very thorough job in reviewing what we did. But we don't have a problem with that. That's done in the normal course of business. That's already provided for under current law.")

Merrimack Station were equivalent concepts, *id.* at 7-8; and that the target population in RSA 369-B:3-a was a subset of the target population in RSA 125-O:11, V. Therefore, for the purposes of this particular type of modification, the "public interest of retail customers of PSNH" and the "public interest of the citizens of New Hampshire and the customers of affected sources" were equivalent, *id.* at 8. As a result of our two findings above, the Legislature's public interest finding under RSA 125-O:11, VI subsumed any public interest finding the Commission might make to pre-approve a modification of Merrimack Station under RSA 369-B:3-a, *id.* at 7-8. Consequently, the Legislature intended the more recent, more specific statute, RSA 125-O:11, to prevail over the modification provisions of RSA 369-B:3-a, *id.* at 8-9; and the Legislature's public interest finding in RSA 125-O:11 precluded a proceeding under RSA 369-B:3-a to examine the public interest of this particular modification, *id.* at 10. We applied a similar rationale in Order No. 24,979 (June 19, 2009), in which we construed the public good determination under RSA 369:1 for approval of a utility financing, part of which might fund the Scrubber installation, to be subsumed by the public interest finding made by the Legislature in RSA 125-O:11. *Id.* at 17.

In our prior orders we did not construe RSA 125-O:11-18 and RSA 369-B:3-a with regard to whether PSNH's continued ownership and operation of Merrimack Station was in the public interest; however, we did not overlook this issue when we issued the clarification in the Second Order on Rehearing. We make our reasoning in the Second Order on Rehearing explicit here. Applying the same analysis to the public interest in divestiture as we applied in Order Nos. 24,898 and 24,979 to the public interest in a modification of Merrimack Station, we concluded that the public interest findings in RSA 125-O:11 do not preclude an inquiry under RSA 369-

B:3-a into the public interest of a decision by PSNH to divest itself of Merrimack Station or to retire that Station prior to divesture.

In coming to this conclusion, we made the following findings which we articulate here. First, installation of Scrubber technology by the owner and operator of Merrimack Station, and PSNH's divestiture of Merrimack Station are not equivalent concepts. Second, the target population in RSA 369-B:3-a is a subset of the target population in RSA 125-O:11, V; however, for the purposes of divestiture, the "public interest of retail customers of PSNH" and the "public interest of the citizens of New Hampshire and the customers of affected sources" are not equivalent. This concept requires explanation. Divestiture is specifically referred to in RSA 125-O:18. That section of the Scrubber Law directs that divestiture and recovery of costs shall be governed by the provisions of RSA 369-B:3-a. RSA 369-B:3-a permits PSNH to divest Merrimack Station if doing so is found to be "in the economic interest of retail customers of PSNH." RSA 369-B:3-a. In the case of Scrubber installation by PSNH without divestiture, the citizens of New Hampshire would enjoy all of the benefits of mercury reduction while all the attendant costs would fall solely on retail default service customers of PSNH. *See* RSA 125-O:18 (prudent costs are recovered in default service rate where utility owns and operates the affected source). In the event of divestiture prior to PSNH's completion of Scrubber installation, both the citizens of New Hampshire and the retail customers of PSNH would have enjoyed all of the benefits of mercury reduction, still with no cost to the citizens of New Hampshire, but potentially with less resulting cost to PSNH's customers. In the event of divestiture following completion of Scrubber installation by PSNH, the citizens of New Hampshire would still enjoy the benefits of mercury reduction, but direct economic impacts would again fall solely upon PSNH customers. In the case of divestiture following completion of Scrubber installation, however, the cost might be borne differently depending upon what services a customer takes from PSNH. Under current law, a utility's prudent costs of the Scrubber installation are recovered in default energy service rates during the utility's ownership and operation of Merrimack Station, RSA 125-O:18, whereas RSA 125-O:18 and RSA 369-B:3-a do not specify the rate components of the mechanism for recovering such costs following retirement or divestiture. *See* RSA 369-B:3-a (PSNH cannot retire or divest its generation assets unless the Commission makes provision for cost recovery).

As a result of these findings, the Legislature's public interest finding under RSA 125-O:11, VI regarding installation of Scrubber technology does not subsume a public interest finding by the Commission under RSA 369-B:3-a regarding PSNH's divestiture of Merrimack Station. Because RSA 125-O:18 calls for a prudence review in a manner determined by the Commission and specifically directs that questions of cost recovery in the event of divestiture be addressed pursuant to RSA 369-B:3-a, the Legislature intended for RSA 369-B:3-a to apply to questions of the public interest in the case of divestiture. Further, the statutory language expressly acknowledges that divestiture was a permissible decision for PSNH to make, subject to a proceeding under RSA 369-B:3-a and an independent economic interest determination[6] by this Commission.[7]

Retirement of Merrimack Station presents slightly different considerations, but the result is the same for this analysis: modification and retirement are not equivalent concepts and a public interest determination regarding one does not subsume a public interest determination regarding the other. Certainly, no one would claim the reverse: that a determination that

[6] *Cf. Appeal of Pinetree Power, Inc.*, 152 N.H. 92, 97 (2005) ("By the plain language of the statute, the public interest standard for modification is broader than just economic interests.").
[7] We emphasize here that we are making no prudence determination at this juncture regarding PSNH's decision to continue ownership of Merrimack Station, only that the issue may be explored at hearing.

retirement of Merrimack Station is in the public interest would be the equivalent of a determination that PSNH should undertake a significant capital investment to comply with mercury reduction laws to thereby keep the facility operational.

The Legislature's public interest findings in the Scrubber Law are not rendered meaningless by our ruling that PSNH had management discretion to divest itself of or to retire Merrimack Station; nor are the Legislature's findings rendered meaningless by our ruling that we have the authority to independently make public interest findings with regard to divestiture or retirement. Instead, these rulings would have, at most, rendered the Legislature's findings either applicable to a different owner in the event of divestiture or moot in the event Merrimack Station ceased operation permanently. Consequently, we reject PSNH's argument that we would have been precluded from making the findings necessary to permit PSNH to divest or retire Merrimack Station, prior to PSNH's completion of its Scrubber project.

D. Constitutional Claims

We reject PSNH's constitutional complaints of denial of due process and non-compensable takings. PSNH argues that our alleged "flip flopping" on the interpretation of RSA 125-O:17 creates a due process violation or has violated PSNH's vested right to construct the Scrubber. In both the First and Second Rehearing Orders in this docket, we acknowledged an apparent inconsistency between our prior construction of RSA 125-O:17 and our construction of that provision in the Discovery Order. We then construed RSA 125-O:17 in the manner championed by PSNH.

More particularly, in the Discovery Order, we reasoned that retirement of Merrimack Station would have provided a basis for PSNH to seek a variance from the Scrubber Law's 80% mercury reduction requirement. Order No. 25,445 at 25. PSNH sought rehearing, pointing out an apparent inconsistency with our previous statement that "[n]owhere in RSA 125-O does the Legislature suggest that an alternative to installing Scrubber technology as a means of mercury compliance may be considered, whether in the form of some other technology or retirement of the facility." *See* Order No. 24,898 at 12. Subsequently, in the First Rehearing Order, we agreed with portions of PSNH's analysis regarding RSA 125-O:17 and concluded that:

> we will not disturb the prior Commission ruling in Order No. 24, 898. To the extent that [the Discovery Order] interpreted the variance provision RSA 125-O:17, to allow retirement of Merrimack Station rather than installation of the scrubber technology as a method of meeting the emissions reduction requirements, that portion of Order No. 25,445 alone is reversed.

First Rehearing Order at 17. We reaffirmed this holding in the Second Rehearing Order:

> Order No. 24,898 . . . confirmed . . . that retirement of Merrimack Station was not recognized as a method of compliance with the mercury reduction requirements of RSA 125-O. . . .[W]e continue to find that our interpretation of RSA 125-O:17 [in Order No. 24,898 and the First Rehearing Order] and the inability of PSNH to use retirement as a means of obtaining a variance from the requirements of RSA 125-O . . . is the correct interpretation.

Second Rehearing Order at 6-7.

PSNH prevailed on its interpretation of whether retirement of Merrimack Station was a recognized method of compliance with the mercury reduction requirements of RSA 125-O, and whether retirement would have formed a legitimate basis for a variance under RSA 125-O:17. It cannot then argue that by accepting its position we have not provided it due process.

PSNH's real complaint is not that we made and corrected an erroneous statement regarding compliance with mercury reduction requirements by retirement pursuant to RSA 125-O:17. PSNH's true disagreement is with our conclusion that, despite our repeated statements that PSNH was under a legislative mandate to construct Scrubber technology, Section 18 of the Scrubber Law retained PSNH's basic duty of prudence not to act irrationally with ratepayer funds, and authorized PSNH to consider its options under RSA 369-B:3-a in the event of changed circumstances. Our prior statements were made in the context of PSNH's decision to continue its ownership and operation of Merrimack Station.

This is a statutory question, and PSNH's argument that it had a vested right to construct the Scrubber does not make the question a constitutional one. The common-law rule of vested rights applies when "an owner, who, relying in good faith on the absence of regulation which would prohibit his proposed project, has made substantial construction on the property or has incurred substantial liabilities relating directly thereto, or both, acquires a vested right to complete his project in spite of the subsequent adoption of an ordinance prohibiting the same." *Appeal of Public Service Co. of N.H.,* 122 N.H. 1062, 1069 (1982). PSNH analogizes its reliance upon the legislative mandate to install Scrubber technology to reliance upon a lack of regulation and the Commission's "newly minted" clarification of the scope of its prudence review to be the subsequent adoption of a prohibitive ordinance. Third Rehearing Motion at 28. Neither analogy holds.

First, PSNH's reliance upon Commission statements that PSNH was under a mandate to construct Scrubber technology is unreasonable. As discussed more fully above, our prior statements in this regard were framed by and made in the context of PSNH's decision to continue its ownership and operation of Merrimack Station. Second, the section governing cost recovery came into effect with the remainder of the Scrubber Law in 2006, well before PSNH incurred liabilities. Further, as discussed above, we stated in 2008 that our eventual prudence review would consider whether "PSNH had been prudent in proceeding with installation of Scrubber technology in light of increased cost estimates and additional costs from other reasonably foreseeable regulatory requirements." Order No. 24,914 at 13. Our interpretation of RSA 125-O:18 and RSA 369-B:3-a is not a sudden, new, or "current creation" of a basis for the

Commission to deny costs as PSNH alleges. Instead, our interpretation of RSA 125-O:18 and RSA 369-B:3-a is an elaboration and refinement of our reading of the statutes that has been a theme of our orders from the outset. We do not believe that elaborating on our interpretation of RSA 125-O:18 in this docket is in any way inappropriate or forms the basis for a due process or a non-compensable taking claim. This is the first proceeding in which the Commission will consider cost recovery in rates pursuant to RSA 125-O:18.

Finally, PSNH's constitutional claims are premature. PSNH has not been denied recovery, and the factual record is incomplete.

E. Prudence Review

We reject PSNH's argument that the Legislature determined in 2006 when it passed the Scrubber Law that PSNH was prudent in installing Scrubber technology at Merrimack Station and that the Commission is precluded from making that determination in this docket. In Section 11 of the Scrubber Law, the Legislature made number of findings, including that "[i]t is in the public interest to achieve significant reduction in mercury emissions at the coal burning electric power plants in the state . . ." RSA 125-O:11, I, "[t]he installation of scrubber technology will . . . reduce mercury emissions . . . with reasonable costs to consumers," RSA 125-O:11, V, and "[t]he installation of such technology is in the public interests of the citizens of New Hampshire and the customers of affected sources." RSA 125-O, VI. While these findings are relevant to whether PSNH acted prudently in its decision to complete the installation of Scrubber technology at Merrimack Station, a prudence review is more encompassing and fundamentally different than a determination that Scrubber technology is best at reducing mercury emissions at a reasonable cost. As we have said in the past, prudence is commonly associated with diligence and contrasted with negligence. *Utility Property Tax Abatements and Limitation of Expenses*, Order No. 21,712, 80 NH PUC 390, 392-93 (1995). When reviewing whether a utility has been prudent in its decision making, we "may reject management decisions when inefficiency, improvidence, economic waste, abuse of discretion or action inimical to the public interest are shown." *Appeal of Easton*, 125 N.H. 205, 215 (1984) *citations and quotations omitted.* Other commissions have taken a similarly broad view of the prudence inquiry:

> [Prudence] is the degree of care required by the circumstances under which the action or conduct is to be exercised and judged by what is known, or could have reasonably been known, at the time of the conduct. In other words, whether an action will be considered prudent depends on whether the action would be considered reasonable by a person with similar skills and knowledge under similar circumstances. It is a term often used interchangeably with what is considered "reasonable" under the circumstances. The Commission must determine whether decisions were made in a reasonable manner in light of the conditions or circumstances that were known or reasonably should have been known when the decision was made.

Duke Energy Indiana, Inc., Cause No. 43114 IGCC 4S1, PUR slip copy at 108, 2012 WL 6759528 at *108 (IURC December 27, 2012). The Legislature did not address PSNH's degree of care in deciding to proceed with the Scrubber project through to its completion. The Legislature appropriately left that review to the Commission, in a manner to be approved by this Commission, once PSNH's decision making process was completed. *Cf.* RSA 125-O:18 and RSA 369-B:3-a.

Based upon the foregoing, it is hereby

ORDERED, rehearing of Order No. 25,546 is hereby DENIED; and it is

FURTHER ORDERED, that Order No. 25,445, Order No. 25,506, Order No. 25,546 and the scope of this docket are clarified as discussed above; and it is

FURTHER ORDERED, that the procedural schedule specified in the Commission's Secretarial Letter dated August 6, 2013, shall be resumed without change.

By order of the Public Utilities Commission of New Hampshire this twenty-seventh day of August, 2013.

Amy L. Ignatius
Chairman

Michael D. Harrington
Commissioner

Attested by:

Debra A. Howland
Executive Director